

REVISED Direct Testimony and Schedules
Greg P. Chamberlain

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in North Dakota

Case No. PU-20-441
Exhibit__(GPC-1)

Policy Testimony

March 26, 2021

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1 I. INTRODUCTION

2
3 Q. PLEASE STATE YOUR NAME, OCCUPATION AND JOB RESPONSIBILITIES.

4 A. My name is Greg P. Chamberlain. I am the Regional Vice President for
5 Northern States Power Company (Xcel Energy or the Company), a Minnesota
6 corporation operating in North Dakota. In this role, I am responsible for state
7 government relations and regulatory filings with the utility commissions in
8 Minnesota, North Dakota, and South Dakota, including proceedings related to
9 rates, resource planning, and service quality filings.

10
11 Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

12 A. I joined Xcel Energy in 2000 and since that time have held various positions in
13 the Company, including in the Transmission and Energy Supply business areas
14 where I worked prior to serving as Regional Vice President for Government
15 and Community Relations, which was the position I held before moving to my
16 current role. While serving as Director of Transmission Portfolio Delivery for
17 the Company, I was responsible for the engineering, project management,
18 project controls, and permitting of a \$4 billion electric transmission capital
19 portfolio across 10 states. In addition, I acted as Xcel Energy’s management
20 committee representative on each of the four CapX2020 projects. As General
21 Manager of Power Generation, I was responsible for the operation of the
22 Company’s non-nuclear fleet of power plants in the upper Midwest. I have a
23 Master of Business Administration degree from the University of Minnesota’s
24 Carlson School of Management and a Bachelor of Science degree in Chemical
25 Engineering from Purdue University. Exhibit ____ (GPC-1), Schedule 1
26 summarizes my qualifications.

1 Q. FOR WHOM ARE YOU TESTIFYING?

2 A. I am testifying on behalf of Xcel Energy.

3

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

5 A. I am presenting the Company's overall rate case to the Commission. My
6 testimony provides an overview of our Application, summarizes the need for a
7 general electric rate increase, explains key developments and strategic initiatives
8 since the Company's last North Dakota rate case, and introduces the Company-
9 sponsored witnesses.

10

11 Q. PLEASE DESCRIBE HOW YOUR TESTIMONY IS ORGANIZED.

12 A. I present my testimony in the following sections:

- 13 • Case Overview;
- 14 • Serving North Dakota;
- 15 • Clean Energy Transition;
- 16 • Rate Case Components;
- 17 • Proposed Changes to Rate Recovery;
- 18 • Introduction of Company Witnesses; and,
- 19 • Conclusion

20

21 Q. ARE THERE ANY OTHER COMPONENTS OF THE COMPANY'S FILING THAT YOU
22 WOULD LIKE TO HIGHLIGHT?

23 A. Yes. We are filing testimony, exhibits, and work papers in support of our
24 request. In addition, we reviewed all North Dakota Public Service Commission
25 Rules and Orders from previous electric rate cases and other dockets to ensure
26 we have complied with the Commission's requirements. My Exhibit___ (GPC-
27 2), Schedule 2, lists the relevant Commission directives, the action the Company

1 has taken to address each directive, and the location in our rate case application
2 of the Company's response.

3 4 II. CASE OVERVIEW

5
6 Q. PLEASE SUMMARIZE THE COMPANY'S REQUEST IN THIS PROCEEDING.

7 A. In this case, Xcel Energy seeks authority from the Commission to increase our
8 electric retail revenues by approximately \$~~19.19722.228~~ million, or ~~9.310.8~~
9 percent. The increase reflects an additional \$~~39.442.4~~ million through base
10 rates, offset by the elimination of \$20.2 million in Transmission Cost Recovery
11 and Renewable Energy Rider (TCR and RER, respectively) charges. We base
12 this request on a 2021 future test year as allowed by North Dakota law. The
13 test year revenue requirement reflects a Return on Equity (ROE) of 10.20
14 percent and an overall Rate of Return (ROR) of 7.35 percent. Under our
15 proposal, a residential customer using 7500 kWh per month would see a
16 monthly bill increase of about \$~~7.358.43~~ per month or ~~8.7510.02~~ percent.

17
18 Q. WHY IS THE COMPANY SEEKING A RATE INCREASE AT THIS TIME?

19 A. The Company last set base rates in its 2012 rate application (using a 2013 test
20 year) (Case No. PU-12-813). At the time, the Company was crossing the peak
21 of an investment cycle in which it was investing in refreshing and upgrading the
22 system. In the policy testimony filed in that case, the Company explained it was
23 then in "in a cycle of significant system investment," including the replacement
24 and refreshing of infrastructure originally built to handle the rapid post-war
25 growth experienced during the 1950s to 1970s. Since the last case, we have
26 completed that system refresh, and while we must always continue to replenish
27 our system so that it continues to provide safe and reliable service, we are now

1 focusing our investments in light of changing customer demands and an
2 evolving business environment for utilities. These investments include
3 modernizing our distribution grid and moving toward a carbon emission free
4 generating fleet.

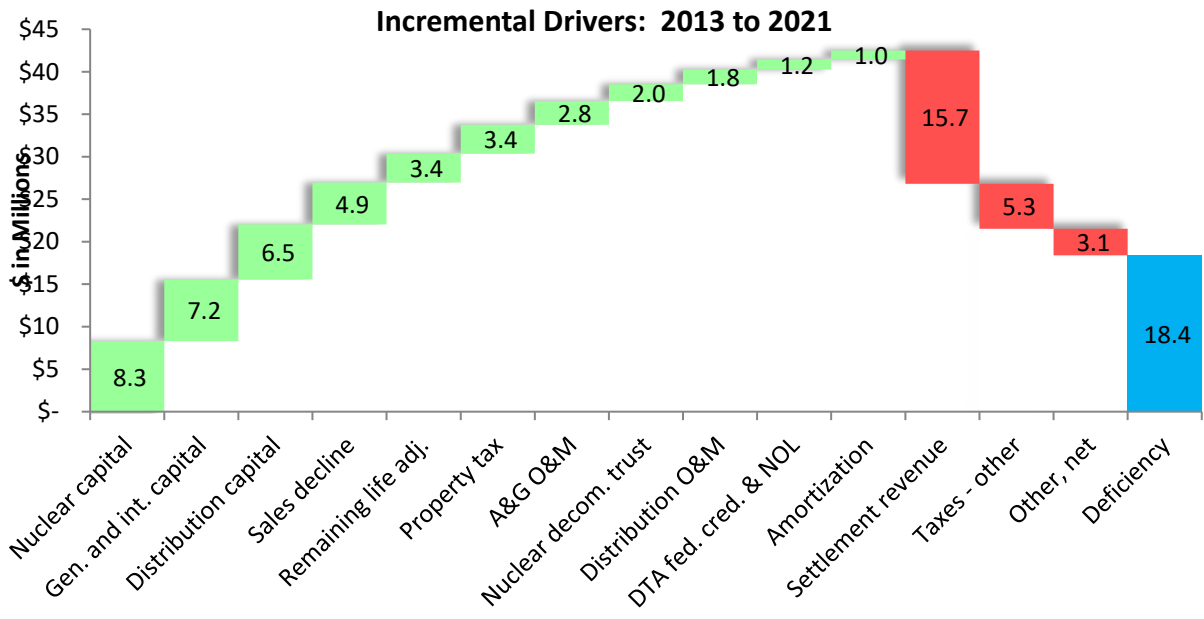
5
6 Since 2013, we have made approximately \$10 billion in capital additions. As a
7 result of our investments, our system is more robust and reliable, and our
8 customers benefit from a diverse mix of generation. Many of our capital
9 investments, including various wind projects that are keeping fuel costs down,
10 have received Advanced Determinations of Prudence (ADPs) from the
11 Commission. Our purchased power, wind and other renewable energy projects
12 are being recovered in the Fuel Cost Rider (FCR) or the RER, but not all of our
13 generation investments are rider eligible and currently being recovered. The
14 impacts of our capital investments are driving the need to increase rates when
15 viewed through the prism of our last case.

16
17 With that said, the outcome of our last rate case not only set base rates for 2013
18 but ultimately resulted in a multi-year outcome, setting rates for 2014, 2015, and
19 2016 as well. In addition, the Company, through two subsequent settlements
20 with Advocacy Staff, also agreed to rate case moratoriums in 2017, 2019, and
21 2020. The results of the multi-year outcome from our 2012 rate application as
22 well as subsequent settlements provided the Company with additional base rate
23 revenue, additional rider revenue, and cost savings from the Tax Cut and Jobs
24 Act (TCJA) that allowed us to continue to earn a reasonable rate of return over
25 the past 8 years without seeking rate relief through a general rate case, even as
26 we continued to make capital investments and our cost of service increased.

1 Figure 1, below, identifies the various categories of costs driving our current
 2 revenue deficiency when compared to currently approved rates (*i.e.*, those
 3 established using a 2013 test year). As Figure 1 below indicates, additional
 4 revenue sources have kept up with the increasing costs of operating our
 5 business, but the impact of our capital investments is now driving the need for
 6 a rate case.

7
 8 **Figure 1**





*Note this figure compares the 2021 test year to the 2013 test year which had a remaining deficiency of \$0.8 million therefore the incremental deficiency above is different than the actual test year deficiency discussed by Company Witness Mr. Benjamin Halama.

As can be seen in Figure 1, the revenue requirements from investments in our nuclear fleet, in refreshing and updating our information technology, and supporting and improving the reliability of our North Dakota distribution system essentially equal the revenue deficiency requested in this case. These investments have resulted in tremendous value for our customers and fully complete the investment cycle that was the driver of our last rate case. I discuss the benefits of these investments further below and additional information regarding these investments is provided in the Direct Testimonies of Mr. Mark P. Moeller and Ms. Kelly A. Bloch.

As can also be seen in Figure 1, additional revenues from the Settlement of our last rate case and cost savings from the TCJA have allowed us to manage the increasing costs of operating our business. However, as Company Witness Ms.

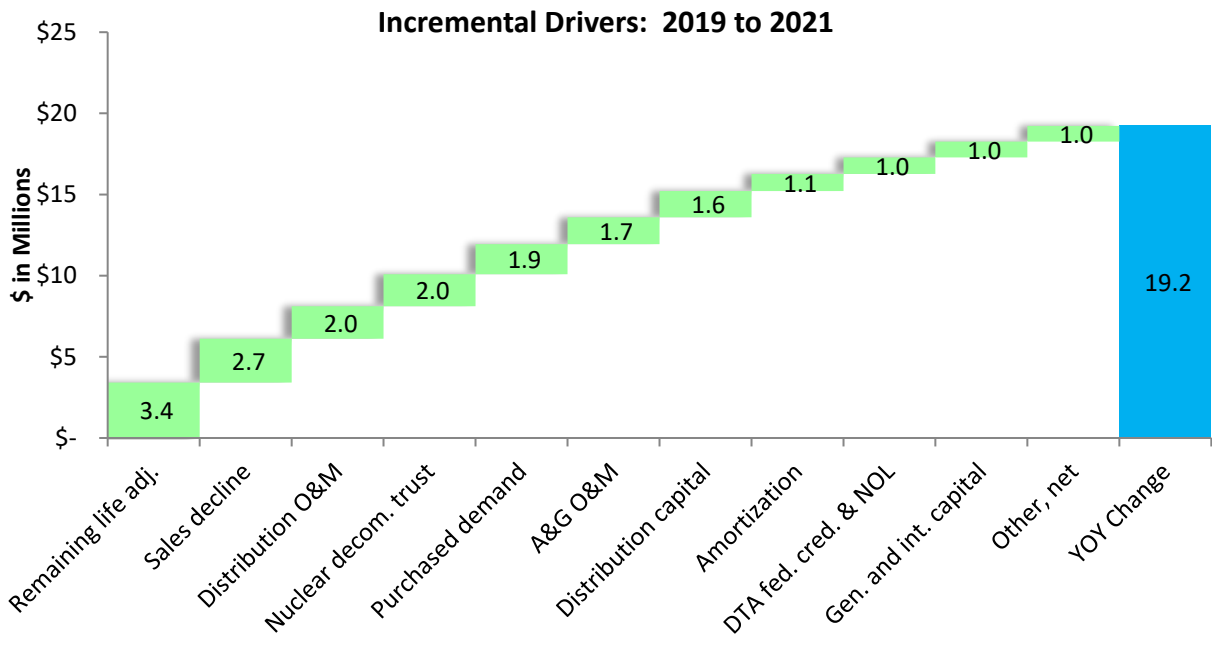
1 Jannell Marks discusses in her Direct Testimony, the Company has seen its
2 overall sales decline since 2013, and we continue to forecast sales declines from
3 our last full fiscal year of 2019. In light of the fact the we must recover our
4 fixed cost of service with fewer kWh of sales, we no longer have the opportunity
5 to earn the reasonable rate of return on our investments necessary to attract
6 capital without additional rate relief. This is consistent with the forecasts relied
7 on by the Company and Advocacy Staff when a rate moratorium through 2020
8 was agreed to and approved by the Commission in Case No. PU-18-155.

9

10 Q. HOW DO THE COMPANY'S COSTS AND REVENUES IN THE 2021 TEST YEAR
11 COMPARE TO 2019 ACTUAL RESULTS?

12 A. Compared to 2019 actual results, the Company has increased costs in the 2021
13 test year including higher distribution expenses, increased capacity costs, and
14 other increased costs due to the passage of time and modernization of our
15 generation assets, transmission system, and distribution system. In addition,
16 retail revenue is decreasing. Figure 2 provides this view.

Figure 2



1 Q. HAS THE COMPANY CONSIDERED THE IMPACT OF THE COVID-19 PANDEMIC
2 ON ITS RATE REQUEST?

3 A. Yes. We recognize that our rate request will impact our customers during these
4 difficult times and we acknowledge that this request comes also as COVID-19
5 has further exacerbated our need for rate relief.

6

7 The impact of COVID-19 on the Company's deficiency is real and pronounced.
8 Figure 1 shows that sales declines since 2013 are contributing to almost \$5
9 million of our deficiency. And, as shown in Figure 2, the impact of the sales
10 decline accounts for more than ten percent of the overall deficiency from 2019-
11 2021. Company Witness Ms. Jannell Marks discusses the impact of COVID-19
12 on our sales and how that is driving the need for rate relief.

13

14 That said, and as I discussed earlier, a material portion of our revenue deficiency
15 is due to the passage of time since our last rate case and the need to update
16 certain ratemaking factors such as depreciation and tax treatment. In light of
17 this, the Company believes there may be opportunities to work with Advocacy
18 Staff to develop and agree to innovative solutions during this rate case to
19 mitigate the impacts of the Company's needed rate relief on customers. We
20 look forward to working with Staff and the Commission during this rate case to
21 find opportunities to resolve this rate case efficiently and in ways that can help
22 us support our customers in these unique times.

23

24 Q. HAS THE COMPANY TAKEN ANY ACTIONS TO PROVIDE RELIEF TO NORTH
25 DAKOTA CUSTOMERS IMPACTED BY THE COVID-19 PANDEMIC?

26 A. Yes. The Company recognizes that the COVID-19 pandemic and the resulting
27 economic impacts are affecting North Dakota. Accordingly, the Company

1 suspended account disconnections through the summer and waived late fees
2 for many of our customers. As the COVID-19 pandemic continues for a longer
3 time than initially expected, we will be reconsidering what additional measures
4 we can take to help support our customers. Providing the rate relief requested
5 will give us additional resources we can use to help our customers through this
6 difficult time.

7
8 Further, the Company has accelerated some planned investments to help
9 support our communities through increased investment, tax base, and
10 construction jobs. For example, in Case No. PU-20-425, we recently requested
11 an Advanced Determination of Prudence for a portfolio of wind repowering
12 projects that includes one of our North Dakota-based wind projects, Border
13 Winds. By making these investments now, we can direct our resources in ways
14 that could support all of our customers by lowering costs in the long-term while
15 also directly investing in our communities. We look forward to further
16 discussion of opportunities for direct investments into North Dakota now and
17 into the future as part of this rate case.

18
19 **III. KEY DEVELOPMENTS AND INVESTMENTS IN SERVING OUR**
20 **NORTH DAKOTA CUSTOMERS**

21
22 Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

23 A. In this section I describe the Company, the outcome of our last rate case to
24 provide context for our current rate request, as well as key Company
25 developments since our last rate case and how these developments are driving
26 our need for rate relief.

1 Q. PLEASE DESCRIBE THE COMPANY.

2 A. Xcel Energy serves more than 1.5 million electricity customers in North Dakota,
3 South Dakota, and Minnesota. The Company is part of an integrated system of
4 generation and transmission that serves the upper Midwest, including Xcel
5 Energy's operations in Wisconsin and Michigan served by NSP-Wisconsin
6 (collectively, the NSP System). Our combined system operations include power
7 plants with a net maximum capacity of almost 9,190 MW, more than 8,400 miles
8 of transmission lines, and approximately 548 transmission and distribution
9 substations.

10

11 Q. HOW DOES XCEL ENERGY'S INTEGRATED SYSTEM HELP TO MEET ITS
12 CUSTOMERS' NEEDS?

13 A. Our integrated NSP System helps to provide cost-effective, reliable, and safe
14 service to all our customers in the Upper Midwest, including those in North
15 Dakota. Our customers across the five states in our Midwest service area derive
16 benefits from an integrated system and a comprehensive approach to planning
17 for and meeting customers' needs. The diversity of our energy supply supports
18 our customers by reducing the risk of significant increases in customer bills due
19 to cost, regulatory, or supply issues that can occur for any one energy source.
20 Our customers also benefit by the fact that many significant business costs can
21 be spread over a larger base, thus lowering the average cost of service.

22

23 Q. WHEN WAS THE COMPANY'S LAST RATE CASE, AND WHAT TEST YEAR IS THE
24 BASIS OF THE COMPANY'S CURRENT RATES?

25 A. The Company filed Case No. PU-12-813 in December 2012 using a 2013 future
26 test year. That 2013 test year is now more than seven years old, but the 2013

1 Cost of Service is still the baseline for our current rate structure, though two
2 additional step increases were implemented in 2014 and 2015.

3
4 Q. WHAT WAS THE OUTCOME OF THE LAST RATE CASE?

5 A. Pursuant to the Settlement Agreement in Case No. PU-12-813, the Company
6 increased rates by 4.9 percent in each of 2013, 2014, and 2015. We also were in
7 a rate case moratorium in 2016 and 2017 and again in 2019 and 2020.

8
9 Q. PLEASE DESCRIBE THE RATE CASE MORATORIUM.

10 A. Pursuant to the Settlement Agreement in Case No. PU-12-813 and the
11 subsequent Negotiated Agreement in the same docket, the Company agreed not
12 to seek an increase in rates in 2016 and 2017. Moreover, in a Settlement in Case
13 No. PU-18-155 the Company agreed not to increase rates in either 2019 or 2020
14 in response to the Commission's investigation of the impacts of the Tax Cuts
15 and Jobs Act (TCJA).

16
17 Q. WHAT TRENDS HAS THE COMPANY SEEN IN RETAIL SALES SINCE 2013?

18 A. From 2010 to 2019, North Dakota retail sales decreased by an average of 0.1
19 percent per year. The decline is not all that surprising, given the growth
20 constraints imposed on our North Dakota service areas due to the state's
21 Territorial Integrity law. And, more recently, Xcel Energy has been
22 experiencing a historic decrease in North Dakota retail sales attributable to the
23 COVID-19 pandemic, and we are forecasting a 2.6 percent decrease in 2020
24 sales compared to 2019. For 2021, the Company is forecasting a 0.5 percent
25 annual increase in North Dakota retail sales, which would represent a partial
26 recovery of sales lost since 2019.

1 Q. WHAT LEVEL OF CAPITAL INVESTMENTS HAS THE COMPANY MADE SINCE 2013?

2 A. Xcel Energy has made approximately \$10 billion in investments into the NSP
3 System to provide safe, reliable, and affordable electricity to our customers.
4 This amount reflects total investments by the Company in the NSP System but
5 only those electric distribution investments made to the North Dakota
6 jurisdiction.

7

8 Q. WHAT WERE THOSE INVESTMENTS?

9 A. As can be seen on Figure 1 above, key capital investments have been made at
10 the Prairie Island and Monticello nuclear plants, including the Monticello life
11 cycle management and extended power uprate project and the replacement of
12 the Unit 2 steam generator at Prairie Island. The Company has also made a
13 wide variety of other investments across our system to provide reliable, safe,
14 and cost-effective service to our customers. In particular, initiatives and
15 individual projects in the following additional areas were primary drivers of our
16 capital additions: wind farms, regional expansion transmission projects, a new
17 natural gas combustion turbine, updates to our information technology and
18 business systems, and the Company's Advanced Grid Intelligence and Security
19 (AGIS) initiative. In addition, the Company made capital investments in
20 distribution substations, poles, cables, and other infrastructure as part of the
21 revitalization of the Company's basic infrastructure discussed in the prior rate
22 case. These investments are discussed by Company witness Mr. Mark Moeller
23 in his Direct Testimony.

1 Q. CAN YOU DESCRIBE THE NUCLEAR CAPITAL INVESTMENTS MADE SINCE 2013 IN
2 GREATER DETAIL?

3 A. Yes, the largest category of capital investments over the last seven years
4 involved Xcel Energy's nuclear fleet. These include improvements required by
5 federal regulators in response to the Fukushima incident; safety, cybersecurity,
6 security, and fire protection improvements; projects undertaken to increase the
7 reliability of the nuclear facilities; the replacement of the steam generator at
8 Prairie Island; the Monticello life cycle management / extended power uprate
9 project; and the license renewal projects (and associated capital additions) at
10 Prairie Island. Investments in the nuclear fleet are continuing in 2020 and are
11 planned for 2021, including reloading of nuclear fuel in Prairie Island Unit 1,
12 further security enhancements, replacement of process control equipment,
13 expansion of the Prairie Island Independent Spent Fuel Storage Installation, and
14 cooling tower refurbishment. Company Witness Mr. Mark Moeller discusses
15 these investments further in his Direct Testimony.

16

17 Q. WHAT HAS BEEN THE RESULT OF THE CAPITAL IMPROVEMENTS OF THE
18 NUCLEAR FACILITIES?

19 A. The projects we have undertaken at Prairie Island and Monticello since 2013
20 were critically important, enabling both plants to continue operating at 95
21 percent capacity or above. In fact, the Company has never had better reliability
22 at its nuclear fleet, and O&M costs for the two facilities are down. In addition,
23 as a result of the improvements made in response to the Fukushima incident
24 and the other security, fire protection, reliability and safety capital
25 improvements made since 2013, the Company's nuclear fleet, which has
26 operated safely since the 1970s, is now even safer, more secure, and more
27 resilient. Indeed, as this testimony is filed, all of our nuclear units are in

1 Exemplary Status as determined by the Institute of Nuclear Power Operations
2 (INPO), all units are in the Nuclear Regulatory Commission’s (NRC) Column
3 1 Status with all green performance indicators, and all units have no NRC Safety
4 Culture Concerns. Prairie Island and Monticello are important sources of low-
5 cost, base load power that are emissions-free, and their continued safe, reliable,
6 and efficient operation are critical to the Company’s commitment to provide
7 reliable and reasonably priced electricity to North Dakota consumers while
8 transitioning to cleaner resources.

9
10 Q. PLEASE DESCRIBE THE COMPANY’S INVESTMENTS IN WIND GENERATION
11 SINCE 2013.

12 A. To harness the excellent wind resource of North Dakota and neighboring
13 states and turn it into clean power for our customers—at a time when market
14 pricing of new wind generation was historically low—the Company invested
15 \$1.3 billion to build 800 megawatts (MW) of new wind facilities across its
16 system between 2013 and 2019.

17
18 The Commission granted ADPs for most of these additions, given the
19 significant benefits that the projects provided to North Dakota customers,
20 including cost savings and a hedge against the volatility of natural gas prices
21 and potential environmental regulation. The Company is continuing to invest
22 in wind generation in 2020 and 2021, and certain such investments are the
23 subject of separate ADP proceedings.

1 Q. PLEASE DISCUSS THE COMPANY'S INVESTMENTS IN REGIONAL EXPANSION
2 TRANSMISSION PROJECTS.

3 A. To meet the growing need for transmission in the region, the Company made
4 capital additions totaling \$1.8 billion in transmission assets, including in
5 regional expansion transmission projects. This includes projects in North
6 Dakota, South Dakota, and Minnesota as part of the CapX2020 initiative. The
7 Company also plans on investing in regional transmission projects in 2021.
8 For example, the Company forecasts a capital addition of \$63 million for the
9 Huntley-Wilmarth Project, which is a Midcontinent Independent System
10 Operator, Inc. (MISO) designated Market Efficiency Project that is designed
11 to provide economic benefits by providing additional transmission capacity to
12 allow low-cost wind generation in southern Minnesota and northern Iowa to
13 reach NSP System customers.

14

15 Q. PLEASE DISCUSS THE COMPANY'S INVESTMENT IN A NEW NATURAL GAS
16 COMBUSTION TURBINE.

17 A. In 2018, the Company placed into service a new natural gas combustion
18 turbine (Unit 6) at our existing Black Dog generating plant in Minnesota. The
19 Company built the new unit to meet a need in the system, and the choice of
20 natural gas reflects the Company's commitment to a robust mix of generation
21 types. The Commission granted an ADP for this investment in Case No. PU-
22 13-194 (Order Adopting Settlement, Feb. 26, 2014).

23

24 Q. PLEASE DESCRIBE THE COMPANY'S INVESTMENTS TO MODERNIZE ITS
25 DISTRIBUTION SYSTEM.

26 A. The Company is now investing to modernize the distribution system in all of
27 the states we serve through our Advanced Grid Intelligence and Security

1 (AGIS) initiative. The AGIS initiative is a long-term strategic plan to transform
2 our electric distribution system to meet multiple ends, including the promotion
3 of efficiency and reliability, and the safe integration of more distributed
4 resources into our system. This initiative will build an advanced electric grid
5 that is more resilient and provides more tools and options for customers. With
6 the need to replace our customers' electric meters in the next 3 to 4 years, we
7 plan to take advantage of the transition period to put more smart technology in
8 place for the long-term benefit of our customers and our overall system. AGIS,
9 and the advanced grid it will create, will offer a number of customer benefits,
10 which are discussed in detail by Ms. Kelly Bloch.

11
12 Q. IS THE COMPANY STILL IN A CYCLE OF SIGNIFICANT CAPITAL INVESTMENT?

13 A. The Company has passed the peak of its cycle of significant capital investment
14 highlighted in Case No. PU-12-813, which was focused on refreshing and
15 replacing aging infrastructure. Now, Xcel Energy is entering a new cycle during
16 which its capital investments are more aimed at transforming and improving the
17 Company's generation, transmission, and distribution systems as the utility
18 industry continues to evolve. Of course, a certain level of basic capital
19 investment is also needed every year to keep the NSP System reliable.

20
21 Q. HAVE THERE BEEN OTHER KEY CHANGES SINCE THE LAST RATE CASE?

22 A. Yes. Two other significant impacts to our cost of service since 2013 are the need
23 to update our depreciation expense and to further fund our nuclear
24 decommissioning trust. Specifically, we need to update our depreciation rates
25 in response to updated information, as depreciable lives for our plants and other
26 infrastructure have not been updated in North Dakota rates since 2008 in Case
27 No. PU-07-776. The most significant change in this regard is the need to update

1 the retirement dates for Units 1 and 2 at Sherco. These dates have been moved
2 forward consistent with the Company's strategy for reducing carbon emissions
3 and making an eventual transition to carbon-free generation. I discuss our
4 carbon reduction plans further in Section III. Company witness Mr. Mark
5 Moeller discusses this and the nuclear decommissioning trust updates further in
6 his Direct Testimony. Company Witness Mr. Christopher Shaw discusses the
7 prudence of retiring Sherco Units 1 and 2 in his Direct Testimony.

8
9 Q. IS THE COMPANY FILING A RATE CASE NOW IN RESPONSE TO THE CAPITAL
10 INVESTMENTS MADE SINCE 2013?

11 A. Yes. When staff and the Company negotiated the multi-year Settlement
12 Agreement in Case No. PU-12-813, we all were aware that the Company was in
13 the process of making significant capital investments, and the terms of the
14 settlement provided for some additional revenues resulting from scheduled rate
15 increases in 2013, 2014, and 2015. Those increases resulted in sufficient revenue
16 increases to cover the Company's increased costs, for a period.

17
18 Then, the passage of the TCJA resulted in tax savings, and the settlement with
19 the Commission in Case No. PU-18-155 allowed Xcel Energy to retain those
20 savings and apply them toward the recovery of the associated revenue
21 requirements of the ongoing cycle of capital investment.

22
23 Taken together, the capital additions made since 2013 which were not
24 recoverable under applicable riders, coupled with the passage of time since our
25 last general rate increase, are driving the need to seek rate relief. These
26 important additions and the decrease in retail sales have, as a general matter,

1 offset the increased revenue resulting from the annual Settlement rate increases
2 and the decreased costs resulting from the TCJA.

3
4 Q. WHAT COSTS ARE CREATING A REVENUE DEFICIENCY FOR 2021?

5 A. As noted above, capital spending and the passage of time since our last rate
6 case, as well as decreasing sales are the primary deficiency drivers. There are
7 also several other factors contributing to increased costs in the 2021 test year.
8 The additional revenue from the multi-year step increases approved in the last
9 rate Settlement and the savings the Company was allowed to keep from the
10 TCJA would be sufficient to cover the increased costs if it were not for the
11 capital investments made since we filed our last rate case.

12
13 Q. IN ADDITION TO THE CAPITAL INVESTMENTS, PASSAGE OF TIME, AND DECREASE
14 IN SALES, WHAT ARE THOSE OTHER FACTORS CONTRIBUTING TO A REVENUE
15 DEFICIENCY?

16 A There are several factors.

17
18 The change in depreciation resulting from a reduction in the remaining lives of
19 Sherco Units 1 and 2 is a significant factor; this is further discussed in the Direct
20 Testimonies of Company Witnesses Mr. Mark Moeller and Mr. Christopher
21 Shaw.

22
23 The Company's administrative and general O&M costs have also increased in
24 light of the premium refund from one of the Company's mutual insurers, NEIL,
25 which offset certain costs in 2019, but which is not expected to be repeated in
26 the test year. Company Witness Mr. Benjamin Halama discusses this further in
27 this Direct Testimony.

1 As Company Witness Ms. Kelly Bloch discusses, certain costs associated with
2 the AGIS initiative as well as other Distribution O&M costs are also increasing.

3
4 Purchased demand expenses, which are not recoverable through the Fuel Cost
5 Rider as purchased energy costs, are increasing as a result of the PPAs with
6 Manitoba Hydro and the PPA for Unit 2 of the Mankato Energy Center (MEC
7 II). Company Witnesses Mr. Benjamin Halama and Mr. Christopher Shaw
8 discuss the increases in our purchased demand costs.

9
10 There are Other Production O&M costs in the test year resulting from new,
11 Commission-approved wind sources. The revenue requirement impacts of
12 establishing a regulatory asset to levelize associated wind energy PTCs over the
13 life of each project, as requested by the Commission, is also a factor. These
14 costs are further described in the Direct Testimony of Company Witness Mr.
15 Benjamin Halama.

16
17 Q. IS THE COMPANY INTERESTED IN ANOTHER MULTI-YEAR OUTCOME SIMILAR TO
18 WHAT WAS ULTIMATELY APPROVED IN ITS LAST RATE CASE?

19 A. Consistent with North Dakota law, the current rate case filing reflects a single,
20 future test year. As in previous rate applications, we look forward to
21 opportunities to discuss with Commission Staff creative ways to resolve this
22 rate case quickly and efficiently. Should a multi-year solution present itself
23 during such discussions, the Company would be willing to seek a mutually
24 acceptable settlement outcome that could include a multi-year solution. The
25 Company has also reached agreements in prior years on multi-year rates with
26 regulators in Minnesota and believes that the resulting rate stability and

1 predictability is to the benefit of customers and the Company, provided
2 consensus can be reached regarding the appropriate design for a multi-year rate.

3
4 **IV. CLEAN ENERGY TRANSITION**

5
6 Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

7 A. In this section of my testimony, I describe Xcel Energy’s plans to transition to
8 clean energy, why this plan is important to the Company’s and our customers’
9 future, and the impact of our clean energy transition on this rate case.

10
11 Q. WHAT IS XCEL ENERGY’S CLEAN ENERGY TRANSITION?

12 A. Xcel Energy, Inc. has announced company-wide goals to reduce carbon
13 emissions 80 percent from 2005 levels by 2030 and serve its customers with 100
14 percent carbon-free electricity by 2050. In our NSP System, working towards
15 this goal will involve modernizing our grid, retiring aging coal-fired generating
16 plants, extending use of nuclear energy, increasing wind and solar generation,
17 and employing efficient natural gas generation during the transition.

18
19 Q. HAVE ANY OTHER UTILITIES ANNOUNCED SIMILAR GOALS?

20 A. Yes. While Xcel Energy is and has been a leader in the development of
21 renewable resources and the transition away from fossil-fueled generation,
22 many other utilities have since announced similar targets. Duke Energy,
23 Southern Company, and Dominion Energy have all announced a goal of
24 achieving net zero carbon emissions by 2050. Arizona Public Service has
25 announced a 100 percent carbon free energy by 2050 goal, American Electric
26 Power announced an “aspirational” goal of zero carbon emissions by 2050,
27 Public Service Enterprise Group (PSEG) has a “vision” of being carbon free by

1 2050, Wisconsin's MGE Energy has a goal to be carbon neutral by 2050, and in
2 Michigan, DTE Energy has a goal of net zero carbon emissions by 2050.

3
4 Some utilities have announced even more aggressive plans to achieve carbon
5 neutrality, zero carbon emissions, or 100 percent clean energy goals. Avangrid
6 has a goal of carbon neutrality by 2035, Avista Energy's goal is carbon neutrality
7 by 2027 and all clean electricity by 2045, Consumers Energy (CMS) in Michigan
8 has a goal of net zero carbon emissions by 2040, Eversource's goal is carbon
9 neutrality by 2030, and Idaho Power has announced its goal of 100 percent clean
10 energy by 2045.

11
12 In addition, various other utilities have announced significant carbon emission
13 reduction goals even if they have not made commitments to completely stop
14 carbon emissions (or net carbon emissions) by a particular year. For example,
15 the Tennessee Valley Authority has announced that it is on track to reduce
16 carbon emissions by 70 percent from 2005 levels by 2030, El Paso Electric has
17 a goal of reducing its carbon footprint by 40 percent (from 2015 levels) by 2035,
18 and NiSource (NIPSCO) has a target of a 50 percent reduction in greenhouse
19 gas emissions by 2025 (from 2005 levels).

20
21 In addition to these examples, other utilities that have announced carbon
22 reduction, or elimination, goals as of the date of this filing are: AES, ALLETE,
23 Alliant, Ameren, CenterPoint, Entergy, Exelon, FirstEnergy, Green Mountain
24 Power, Hawaiian Electric, National Grid, NextEra, OG&E, PG&E, Portland
25 General Electric, PPL, Puget Sound Energy, Southern California Edison,
26 Tucson Electric Power, UGI Utilities, Vectren, and WEC Energy Group.

1 Across the industry, utilities of various sizes, with different business models and
2 fleets, operating in a variety of jurisdictions, including in jurisdictions where
3 public utility commissions and state legislatures are traditionally supportive of
4 fossil fuel generation, have recognized that transitioning to lower-carbon
5 generation and, eventually, carbon-free generation is the prudent course of
6 action.

7
8 Q. WHAT ABOUT THE OTHER INVESTOR-OWNED UTILITIES IN NORTH DAKOTA?

9 A. While Otter Tail Power Company and MDU Resources have not announced
10 goals to achieve carbon-free generation by some set date, both have stated
11 carbon emission reduction goals. MDU has a target of reducing its carbon
12 emission intensity by 45 percent by 2030 (from 2005 levels). For its part, Otter
13 Tail Power has stated that by 2022 it will have reduced carbon emissions by
14 nearly 30 percent (from 2005 levels). Also, as the Commission knows, the move
15 away from carbon-intensive generation is resulting in the closure of several coal-
16 fired plants, including facilities located in or serving North Dakota. Otter Tail
17 Power's Hoot Lake facility is slated for closure in 2021, MDU's Lewis & Clark
18 Unit 1 is also to close in 2021, and Units 1&2 at MDU's Haskett plant are
19 scheduled for a 2022 closure.

20
21 In addition, Great River Energy closed the Stanton facility in 2017, and also
22 plans to close the Coal Creek facility by the end of 2022.

23
24 The Company's decision to move forward the retirement dates for Sherco Units
25 1 and 2 is thus consistent with the decisions regarding coal-fired plants in North
26 Dakota, including those owned by other utilities in the state. The transition

1 away from coal generation and towards lower carbon and carbon-free
2 generation is already well underway both nationwide and in North Dakota.

3
4 Q. WHAT FACTORS ARE PUSHING UTILITIES TO TRANSITION TO CARBON-FREE
5 GENERATION OVER THE NEXT FEW DECADES?

6 A. The electric utility industry is in the relatively early stages of a decades-long
7 transition away from fossil-fueled generation. This transition is driven by a
8 number of factors including the following:

- 9 • reduced costs of renewable generation (and trends and forecasts
10 suggesting those costs will continue to decrease);
- 11 • environmental concerns (including among consumers and other
12 members of the public);
- 13 • regulatory pressure in some states and the prospect of future regulatory
14 pressure at the federal level;
- 15 • higher operation and maintenance costs for certain coal and natural-gas
16 generation facilities (particularly older facilities);
- 17 • environmental compliance costs associated with contaminants regulated
18 at the state and federal levels (MATS standards, for example, resulted in
19 the closure of some older coal plants);
- 20 • continued efficient operation of nuclear generation facilities;
- 21 • the ability to extend the operational lives for nuclear generation
22 facilities;
- 23 • advancements in energy storage technologies (and, perhaps more
24 importantly, the prospects for future innovation);
- 25 • the lack of fuel costs for solar and wind generation, investor and
26 customer concerns about carbon emissions and climate change;

- 1 • lower financing costs for renewable resources; and
- 2 • the availability of low-cost, efficient natural gas generation to serve as a
- 3 lower emission bridge technology during this transitional period.

4

5 With all these factors in play, it is no surprise that so many utilities have publicly

6 announced carbon emission reduction goals.

7

8 Q. HOW DOES THE COMPANY PLAN TO MANAGE THIS TRANSITION?

9 A. The transition away from carbon-emitting generation is going to continue and

10 will benefit Xcel Energy’s customers, particularly if it is carefully planned and

11 managed as the Company intends and has been doing. As a result of its

12 continuing leadership in the use of renewables, an effort in which North

13 Dakota-based wind generation plays a crucial part, and its recent investments in

14 its nuclear fleet, Xcel Energy is already in a strong position to manage the

15 transition to carbon-free generation over the few decades. By being an industry

16 leader and setting an ambitious goal (that other utilities have also subsequently

17 sought to achieve), the Company is positioning itself to thoughtfully and

18 efficiently transitioning for the ultimate benefit of consumers.

19

20 As we transition toward carbon-free generation we are working to keep costs

21 down through the use of low cost renewable generation, the low cost and

22 efficient management of the Company’s nuclear fleet, the replacement of fossil

23 fuel costs with fixed assets (the Company’s “Steel for Fuel” strategy), the low

24 costs of natural gas generation (during the transitional period), and favorable

25 financing costs for renewable resources. By starting the transition to carbon-

26 free generation early and making the necessary improvements to our system

27 (including certain investments that have already been made or are underway),

1 Xcel Energy will be able to manage this transition in a manner that keeps
2 electricity affordable while maintaining reliability.

3
4 If the Company were to postpone or unduly slow the process, it would risk a
5 future in which it would have to undertake substantial changes in generation
6 and transmission assets in a relatively short period of time, which is more likely
7 to lead to excessive costs and reliability concerns. While Xcel Energy believes
8 the trend toward de-carbonization will continue even without action at the
9 Federal level, a renewed Federal effort in regulating carbon emissions could
10 accelerate trends, perhaps as a result of electoral politics over the next ten to
11 fifteen years.

12
13 Q. YOU MENTIONED A LOWER FINANCING COST FOR RENEWABLES, CAN YOU
14 PLEASE EXPLAIN THAT?

15 A. Yes. The Company has been able to finance wind projects by issuing so-called
16 “green bonds.” The proceeds from green bonds are dedicated by issuers to be
17 used for investments in renewable energy projects. One advantage of such
18 bonds is that they attract additional investors who are looking to invest in green
19 projects or renewables, including some investors who focus on investments
20 such as socially responsible mutual funds. This additional pool of potential
21 investors has resulted in lower-cost financing for the Company, including, for
22 example, a 3.7 percent green bond issued in September 2019, which set a record
23 for the lowest interest rate for a 30-year utility bond in history. In 2018 and
24 2019, we issued approximately \$580,000,000 in green bonds to finance wind
25 projects. We believe green bonds will continue to play a significant role in Xcel
26 Energy’s financing for renewable projects and could also be a possibility for
27 future storage projects. Additionally, customers benefit from the Company’s

1 issuance of green bonds because the lower interest rates lower the Company's
2 cost of capital.

3
4 Q. YOU ALSO REFERRED TO INTEREST AND PRESSURE FROM INVESTORS. PLEASE
5 EXPLAIN.

6 A. Increasingly, investors, including large institutional investors, are considering
7 the impacts of greenhouse gas emissions when making investment decisions.
8 Some of Xcel Energy's largest institutional investors are members of Ceres
9 and/or Climate Action 100+, which are both groups of institutional investors
10 who make efforts to push corporations to reduce their carbon emissions. Some
11 of the institutional investors in question include Black Rock, JP Morgan Asset
12 Management, State Street, Pictet Asset Management, and CalPERS. Those
13 investors who push for emission reductions typically make the point that efforts
14 to reduce emissions promote the long-term value of a company. For example,
15 in an open letter to CEOs, Black Rock's Chairman and CEO described climate
16 risk as an investment risk and indicated that his firm would increasingly be
17 evaluating companies based on whether "companies are properly managing and
18 overseeing these risks within their business and adequately planning for the
19 future."

20
21 Investment analysts have also recognized the advantages of a transition toward
22 carbon-free generation. For example, in a December 2019 report, analysts at
23 Morgan Stanley touted the economic benefits of replacing coal generation with
24 lower-cost renewables.

1 Q. IN THE NEGOTIATED AGREEMENT IN CASE NO. PU-12-813, XCEL ENERGY
2 COMMITTED TO BUILD THERMAL GENERATION IN EASTERN NORTH DAKOTA
3 WITH A CAPACITY OF AT LEAST 200 MW BY THE END OF 2025, CONSISTENT WITH
4 PRUDENT RESOURCE PLANNING PRINCIPLES. WHERE DOES THAT COMMITMENT
5 STAND IN LIGHT OF THE COMPANY’S GOALS?

6 A. The Company recognizes its prior commitment, and our current long term
7 resource plan also reflects the need for additional resources in the mid-2020s
8 and our commitment to building generation in North Dakota. The precise
9 resource types and timeframes during which they would be added is not yet
10 certain but will be considered in the Action Plan included in our next resource
11 planning cycle. We recognize that natural gas generation plays an important
12 role in our long-term transition away from carbon emissions. However, the
13 lifespan of that natural gas facility could be somewhat limited due to the
14 Company’s 2050 goal; accordingly, the Company is open to discussing possible
15 alternatives to the project, if the Commission so desires.

16
17 Q. HOW DOES THE COMPANY’S CARBON-FREE GOAL FIT WITH THE RESOURCE
18 TREATMENT FRAMEWORK ADDRESSED IN CASE NO. PU-12-813?

19 A. In the Settlement Agreement in Case No. PU-12-813, the Company and Staff
20 agreed to work together to develop a methodology to reflect a “restacking” of
21 the resources on the NSP System for purposes of ratemaking in North Dakota.
22 Later, the Company and Staff agreed to the Negotiated Agreement, which was
23 approved by the Commission and included, among other things, a requirement
24 for the Company to put forward a “Resource Treatment Framework” or “RTF”
25 that would better reflect North Dakota energy policy in its North Dakota rates.
26 The Company met those commitments through its subsequent RTF filing in

1 Case No. PU-12-813, and its filing on December 21, 2018, which presented a
2 proposed North Dakota Resource Planning (NDRP) framework.

3
4 At a high-level, the RTF is the Company's proposal to resolve the misalignment
5 among North Dakota, South Dakota, and Minnesota policymakers with respect
6 to the types of resource additions proposed by the Company for the NSP
7 System. As a practical matter, the misalignment related to higher-cost wind and
8 solar resource additions to the NSP System, which were relevant to the
9 Company's 2030 and 2050 goals. Starting in January 2017, the Company, in
10 collaboration with Commission Staff and the Commissioners, worked to
11 develop a viable RTF. The resulting RTF was composed of two separate, but
12 interrelated, components: (1) development of a new, formal North Dakota
13 Resource Planning procedure for the Company; and (2) implementation of the
14 appropriate ratemaking and resource allocation methodologies (for the
15 associated capacity, energy, revenue, costs, and other attributes) for resources
16 that would not be approved by all of the NSP System states.

17
18 However, in the years since 2013, the policy misalignment between North
19 Dakota, South Dakota, and Minnesota has diminished given the much more
20 competitive wind energy prices, such that an RTF may no longer be necessary.
21 In recent years, there has been more alignment of all of the NSP System states
22 with respect to the significant wind resource additions proposed by the
23 Company. Since the Company's last rate case, the Commission granted ADPs
24 for the addition of wind-generation, either owned by the Company or acquired
25 through PPAs, in Case Nos. PU-18-430, PU-17-372, PU-17-120, PU-15-181,
26 PU-13-742, and PU-13-706.

1 In this rate case, the Company is requesting to reflect in rates its power purchase
2 agreement for MEC II and the 187 MW Solar Portfolio. The Company's ADP
3 request for the proposed purchase of the entire Mankato Energy Center was
4 withdrawn in Case No. PU-18-403, and our ADP request for the solar portfolio
5 was dismissed, without prejudice, in Case No. PU-14-810. The Company
6 believes that these resource additions are prudent and in the best interest of
7 customers based on the information available at the time that the resource
8 decisions in question were made. Company witness Mr. Christopher Shaw
9 provides support for the Company's request. In the event that the Commission
10 does not approve rate recovery for these resource additions in this rate case that
11 have been approved elsewhere, it may be appropriate to apply to those resources
12 ratemaking treatments similar to what was contemplated in the Company's RTF
13 filing.

14
15 Q. HOW DOES THIS RATE CASE FILING SUPPORT THE COMPANY'S LONG-TERM
16 GOALS?

17 A. Investments described in this case generally relate to four key areas: 1) our
18 continued transition to renewable energy generation, 2) our industry-leading
19 nuclear operations, 3) depreciation reserve rates, and 4) our AGIS initiative.
20 The investments and expenses in these areas are tied to the Company's interim
21 goal of reducing carbon emissions 80 percent by 2030. Our subsequent goal of
22 carbon-free electrical generation will require additional technological
23 developments, and the capital improvements and O&M expenses associated
24 with implementing those future technologies will be the subject of future cycles
25 of investment.

1 Q. HOW DO XCEL ENERGY'S INVESTMENTS IN RENEWABLE ENERGY GENERATION
2 IMPACT THIS FILING?

3 A. As I have noted above, Xcel Energy has long been at the forefront of the
4 industry with respect to renewable energy, and those efforts continue as we have
5 been engaged in the largest build-out of new wind resources in the Company's
6 history, for which the Commission granted an ADP. Our expansion of
7 renewable generation impacts this rate case filing in two principle ways.

8

9 First, as Mr. Halama and I discuss, we propose to "roll in" to base rates a
10 number of wind projects currently being recovered through the Renewable
11 Energy Rider (RER). However, it should be noted that, while the roll-in of
12 these projects will increase base rates, there will not be a material change in
13 customer bills as recovery already occurs through the RER.

14

15 Second, the increase in wind generation impacts fuel costs and our O&M
16 expenses. The new wind resources are part of our "Steel for Fuel" strategy;
17 generation sources that require the purchase of coal or natural gas are replaced
18 with wind resources that do not require such fuel. Those reductions have
19 already begun to be reflected in the FCR and will continue to benefit customers
20 going forward, which helps maintain the overall affordability of energy for
21 customers as Xcel Energy continually reduces its use of fossil fuels. Moreover,
22 as renewable sources continue to become a larger part of the fleet, we see a
23 larger part of our O&M budget going toward the maintenance of those
24 renewable facilities. At the same time, we are seeing reductions in O&M
25 expenses for fossil fuel facilities. Last, the tax implications of our shift to
26 renewable resources, which produce federal Production Tax Credits (PTCs),
27 also impact our cost of service through adjustments to our deferred tax asset

1 (DTA). The DTA allows us to pass the benefits of PTCs to our customers and
2 to levelize the PTC benefits to customers over the life of the given wind project
3 as directed by the Commission. Company Witness Mr. Benjamin Halama
4 discusses the DTA and PTC levelization further in this Direct Testimony.

5
6 Q. WHAT RESULTS HAS THE COMPANY SEEN TO DATE FROM THE STEEL FOR FUEL
7 STRATEGY?

8 A. The Steel for Fuel strategy has been successful. By adding wind resources to
9 the NSP System, the Company has significantly reduced its fuel costs. In 2013,
10 our average North Dakota fuel costs were 2.9 cents per kilowatt hour (kWh).
11 For 2020, we are forecasting that our average fuel costs will be 1.85 cents per
12 kWh. That is a 34 percent reduction. As more wind is added to the system, we
13 anticipate that fuel costs will continue to decline.

14
15 Q. WHY ARE CAPITAL INVESTMENTS AND O&M EXPENSES RELATED TO THE
16 NUCLEAR FLEET SO IMPORTANT?

17 A. Together, the Monticello and Prairie Island make up more than half of our
18 existing carbon-free generation and one-third of our total generation, providing
19 enough energy to serve more than one million customer homes. The continued
20 role of nuclear generation is therefore critical to our long-term carbon emission
21 reduction goals.

22
23 Accordingly, O&M and capital expenses for the nuclear fleet are important for
24 maintaining affordable and reliable electrical service while Xcel Energy
25 transitions to carbon-free generation. As I noted earlier, our nuclear plants are
26 operating safely, reliably, and efficiently. The Company made significant capital

1 investments in its nuclear fleet between the 2013 rate case and the date of this
2 filing, and it is appropriate to add such improvements to the rate base.

3
4 Q. HOW DO CHANGES IN THE COMPANY'S DEPRECIATION RATES RELATE TO THE
5 COMPANY'S CARBON EMISSION REDUCTION GOALS?

6 A. In this rate case, the Company is seeking to adjust depreciation expenses for
7 Sherco Units 1 and 2 to reflect the new 2026 and 2023 retirement dates,
8 respectively, for these units. The near-term retirement of Units 1 and 2 at
9 Sherco are a crucial part of the Company's strategy to achieve its goal of
10 reducing carbon emissions by 80 percent by 2030.

11
12 Q. HOW DOES THE COMPANY'S AGIS INITIATIVE SUPPORT THE CLEAN ENERGY
13 TRANSITION?

14 A. As I noted above, the AGIS initiative is a long-term strategic plan to transform
15 our electric distribution system to achieve multiple ends, including the
16 promotion of efficiency and reliability, and the safe integration of more
17 distributed resources and storage into our system. Modernizing the grid is a
18 complex, long-term project. Xcel Energy is taking a leading industry role in grid
19 modernization, and we expect that the investments made now, and the lessons
20 learned in implementing AGIS, will have long-term benefits as the transition to
21 carbon free generation proceeds.

1 **V. RATE CASE COMPONENTS**

2

3 **A. Test Year**

4 Q. WHAT INFORMATION IS THE COMPANY PROVIDING TO SUPPORT ITS 2021 TEST
5 YEAR IN THIS CASE?

6 A. Consistent with N.D.C.C. § 49-05-4.1, the Company includes the following in
7 this application to substantiate its 2021 test year:

8 a. A comparison of forecast data to historical period data to demonstrate
9 the reliability and accuracy of the utility’s forecast including a comparison
10 of the prior years’ forecast or budgeted data to actual data for those
11 periods is provided in the Direct Testimony of Company Witness Mr.
12 Benjamin Halama.

13

14 b. A statement that the public utility’s forecast is reasonable, reliable, and
15 was made in good faith and that all basic assumptions used in making or
16 supporting the forecast are reasonable, evaluated, identified, and justified
17 to allow the commission to test the appropriateness of the forecast is
18 provided in the Direct Testimony of Company Witness Mr. Benjamin
19 Halama.

20

21 c. A statement that the accounting treatment that has been applied to
22 anticipate events and transactions in the forecast is the same as the
23 accounting treatment to be applied in recording the events once they
24 have occurred. This information is provided in the Direct Testimony of
25 Company Witness Mr. Benjamin Halama.

1 **B. Rate of Return**

2 Q. WHAT RATES OF RETURN IS THE COMPANY PROPOSING IN THIS APPLICATION?

3 A. Our proposed revenue requirement reflects an overall rate of return (ROR) on
4 investment of 7.35 percent, based on an average common equity ratio of 52.50
5 percent and an ROE of 10.20 percent. Company Witness Mr. Dylan
6 D'Ascendis provides a detailed analysis of the appropriate overall ROR and
7 ROE for the Company.

8
9 **C. Revenue Requirements**

10 Q. WHAT BASE RATE REVENUE REQUIREMENT IS THE COMPANY PROPOSING IN
11 THIS RATE CASE?

12 A. The Company is proposing a revenue requirement of \$~~225.613228.644~~ million,
13 which is an overall base rate increase of \$~~39.442.4~~ million, offset by the
14 elimination of \$20.2 million in from the TCR and RER. When the reduction
15 of rider revenue is netted with the Company's request, the overall revenue
16 deficiency sought in this rate case is \$~~19.19722.228~~ million or ~~9.310.8~~ percent.

17
18 Q. IS THE COMPANY SEEKING ANY OTHER ADDITIONAL REVENUE THROUGH THIS
19 RATE CASE?

20 A. Yes. We are requesting that the Commission allow the recovery for the costs
21 of the 187 MW Solar Portfolio in our FCR as discussed in the Direct Testimony
22 of Mr. Christopher Shaw.

1 **D. Rate Design**

2 Q. PLEASE DESCRIBE YOUR PROPOSED RATE DESIGN FOR THIS CASE.

3 A. We are not proposing any material changes to the current rate design. Company
4 Witness Mr. Nicholas Paluck discusses this further and identifies the minor
5 proposed rate design changes.

6
7 **VI. PROPOSED CHANGES TO RATE RECOVERY**

8
9 Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

10 A. In this section of my Testimony, I discuss the Company’s proposed changes to
11 certain ratemaking items related to employee compensation and benefits,
12 charitable donation and association dues, and recovery of certain deferred
13 expenses.

14
15 Q. IS THE COMPANY SEEKING TO MAKE ANY CHANGES TO RATE RECOVERY
16 ASSOCIATED WITH HUMAN RESOURCES AND EMPLOYEE COMPENSATION?

17 A. Yes, we are seeking to adjust the extent to which two forms of incentive pay are
18 considered in determining base rates in North Dakota. The two incentive
19 programs are: 1) the Annual Incentive Program (AIP) and 2) the Long-Term
20 Incentive program (LTI).

21
22 Q WHAT IS AIP AND WHY IS IT IMPORTANT?

23 A. AIP is an important component of compensation for Xcel Energy’s exempt,
24 non-bargaining employees. All exempt, non-bargaining employees are eligible
25 to receive AIP. Those eligible employees each have a targeted annual incentive,
26 expressed as a percentage of base pay, and they can earn those incentives
27 through achievement of individual performance goals and by the Company’s

1 achievement of corporate Key Performance Indicators. In 2020, the Key
2 Performance Indicators are residential customer satisfaction, managing O&M,
3 employee safety, public safety, and electric system reliability. The Company
4 anticipates using similar Key Performance Indicators for 2021.

5
6 AIP serves several critical functions for the Company. By paying employees
7 based on performance, the Company provides additional motivation for
8 individual employee performance. Also, AIP brings the Company's employee
9 compensation in line with market levels. On the latter point, Xcel Energy is
10 aware that its peer local and national investor-owned utilities also have incentive
11 pay programs. Without AIP, Xcel Energy's compensation program would not
12 be in line with competitors and it would find it more difficult to attract and
13 retain exempt, non-bargaining employees.

14
15 Like any employer, Xcel Energy has always had to compete in the labor market
16 for quality employees, and customers benefit when the appropriate employees
17 are operating the electrical generation, distribution, and transmission systems.
18 However, as the utility industry changes, and information technology is
19 increasingly integrated into utility operations in new and more complicated
20 ways, the Company requires employees with new sets of skills and finds itself
21 competing more against non-utility employers. For example, Xcel Energy now
22 has a greater need for cybersecurity professionals than at any point in its history
23 and employees with those backgrounds can work in a variety of industries. The
24 result is that maintaining a competitive compensation package is now even more
25 important than was the case in prior generations.

1 Q. HOW WAS THE AIP ADDRESSED IN THE LAST RATE CASE?
2 A. In Case No. PU-12-813, the Company initially sought recovery of AIP costs of
3 up to 25 percent above base pay. However, in settling the matter, Xcel Energy
4 agreed to exclude AIP costs above 15 percent of base pay from rates.
5
6 Q. WHAT IS THE COMPANY'S PROPOSAL FOR HOW AIP SHOULD BE ADDRESSED IN
7 THIS RATE CASE?
8 A. The Company is proposing that it be allowed to recover AIP expenses up to 20
9 percent of base pay. This proposed increase from the current 15 percent cap
10 will help the Company recover the costs of employee compensation necessary
11 to attract and retain qualified employees. Company Witness Mr. Benjamin
12 Halama discusses the impacts on the rate case of this proposal.
13
14 Q. WHAT IS LTI?
15 A. LTI is an incentive program that is available to a smaller set of employees than
16 AIP. While AIP is available to all exempt, non-bargaining employees, less than
17 five percent of exempt and non-bargaining employees are eligible for LTI. The
18 employees who receive an LTI grant tend to be those who have a higher level of
19 influence in the Company's direction and strategy, and also are employees who
20 are in positions that can be expensive and time-consuming to fill. The LTI
21 program helps retain these key employees and, like API, is necessary for Xcel
22 Energy to remain competitive in the labor market.
23
24 Q. WHAT COMPONENTS GO INTO LTI?
25 A. Three components go into LTI: 1) environmental performance, 2) total
26 shareholder return LTI, and 3) time-based LTI. However, the Company is only

1 seeking recovery for the environmental LTI costs. The Company is not seeking
2 to have the other two components recovered through customer rates.

3
4 Q. WHAT IS ENVIRONMENTAL LTI?

5 A. Environmental LTI is the portion of the LTI program tied into the achievement
6 of the Company's carbon emission reduction goals. As I discussed earlier in
7 Section III, the Company is a leader in seeking to reduce carbon emissions.
8 Xcel Energy's customers will benefit from the Company's transition away from
9 carbon generation, particularly when compared to those companies who are
10 slow to embrace change. The technologies implemented by Xcel Energy will
11 result in efficiencies, allow for a lower cost of capital, and remove fuel costs, in
12 addition to environmental benefits and other benefits. Given the benefits of
13 carbon reduction, which are now recognized in the market as reflected by the
14 actions being taken by so many of Xcel Energy's peers, it makes sense for the
15 Company to provide incentives for its key decision makers to keep the
16 Company on track to reduce carbon emissions 80 percent by 2030 and 100
17 percent by 2050.

18
19 Q. WHAT IS THE COMPANY'S PROPOSAL FOR HOW LTI SHOULD BE ADDRESSED IN
20 THIS RATE CASE?

21 A. The Company is proposing that it be allowed to recover the environmental
22 portion of its LTI expenses. Company Witness Mr. Benjamin Halama discusses
23 the impacts on the rate case of allowing for rate recovery of LTI.

1 Q. WHAT CHANGES IS THE COMPANY SEEKING WITH REGARD TO CHARITABLE
2 CONTRIBUTIONS?

3 A. Currently, the cost of charitable contributions that benefit North Dakota are
4 not recoverable in North Dakota rates. The Company is proposing that cost
5 recovery of 50 percent be allowed. Charitable contributions are a normal and
6 expected expense for a business, particularly for a corporation of Xcel Energy's
7 size and prominence in the community, and the Company's request is moderate
8 in that it only encompasses half the cost of those donations that directly benefit
9 North Dakota.

10

11 The Company is also seeking to recover 100 percent of the cost of a limited set
12 of contributions: donations made to North Dakota state and local economic
13 development entities. Company Witness Mr. Benjamin Halama discusses the
14 rate impact of this change in this Direct Testimony. The impact on rates of the
15 Company's proposal will be quite modest, and North Dakota benefits when the
16 Company makes such contributions.

17

18 Q. WHAT IS THE COMPANY'S PROPOSAL WITH REGARD TO CHAMBER OF
19 COMMERCE DUES?

20 A. The Company is proposing that it be allowed to recover 50 percent of the cost
21 of membership dues for the Greater North Dakota Chamber of Commerce. As
22 with charitable contributions, such dues are a common business expense.
23 Moreover, participation in the Chamber of Commerce can facilitate important
24 discussions between Xcel Energy and other members of the North Dakota
25 business community, including industrial and commercial clients, to the benefit
26 of the Company and its customers. Company Witness Mr. Benjamin Halama
27 discusses the rate impact of this change in this Direct Testimony.

1 Q. WHAT IS THE RTF EXPENSE DEFERRAL?

2 A. As I discussed above, the Company, acting pursuant to the Settlement in Case
3 No. PU-12-183, worked to develop and submit an RTF in order to resolve
4 policy misalignments between North Dakota, South Dakota, and Minnesota
5 regarding the types of generation assets that should be added to the NSP
6 System. The Company spent approximately \$1.8 million creating the RTF. The
7 recovery of RTF cost was deferred pending adoption of the RTF. Company
8 Witness Mr. Benjamin Halama discusses this further in his Direct Testimony.

9

10 VII. INTRODUCTION OF COMPANY WITNESSES

11

12 Q. WHO ARE THE WITNESSES FOR THE COMPANY IN THIS PROCEEDING?

13 A. In addition to my Policy Testimony, the Company sponsors the following
14 witnesses:

15 • *Benjamin Halama*, who sponsors the overall revenue requirement for the
16 rate case. Mr. Halama sponsors the schedules supporting our income
17 statement, rate base, revenue deficiency, and jurisdictional allocations.

18 • *Dylan D'Ascendis*, of ScottMadden, Inc., who sponsors testimony on the
19 ROE and ROR including capital structure and cost of capital.

20 • *Jannell E. Marks*, who sponsors testimony regarding the Company's sales
21 forecast and demand allocator.

22 • *Kelly A. Bloch*, who sponsors testimony regarding the Company's
23 distribution capital and O&M budgets and the Advanced Grid
24 Intelligence and Security (AGIS) initiative.

25 • *Mark P. Moeller*, who sponsors testimony regarding the Company's
26 depreciation expenses, accumulated depreciation, and capital roll-
27 forward.

- 1 • *Christopher P. Shaw*, who sponsors the Company’s support for the
- 2 prudence of the MEC II PPA, the adjusted end of life for Sherco Units
- 3 1 and 2, the cancellation of the Prairie Island Extended Power Uprate
- 4 project, the 187 MW Solar Portfolio, and the Company’s acquisition of
- 5 the Community Wind North and Jeffers Wind repowering projects.
- 6 • *Michael Peppin*, who sponsors our class cost of service study.
- 7 • *Nicholas Paluck*, who sponsors rate design and tariff changes.

8
9 Together, these witnesses provide the information and advocacy needed to
10 evaluate and approve our Application.

11 12 VIII. CONCLUSION

13
14 Q. PLEASE SUMMARIZE THE COMPANY’S REQUEST TO THE COMMISSION.

15 A. We respectfully request that the Commission approve:

- 16 • Our requested rates that provide a net incremental revenue requirement
- 17 increase of \$~~19.197~~ ~~22.228~~ million;
- 18 • An overall ROR on investment of 7.35 percent, based on an average
- 19 common equity ratio of 52.50 percent and an ROE of 10.20 percent; and
- 20 • Minor changes to our rate design.

21
22 Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

23 A. Yes.