Direct Testimony and Schedules
Aakash H. Chandarana

Before the Public Utilities Commission
of the State of South Dakota

In the Matter of Commission Staff's Request to Investigate
Northern States Power Company d/b/a Xcel Energy's
Proposed Fuel Clause Rider

Docket No. EL16-037
Exhibit___(AHC-1)

Policy

June 30, 2017

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Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Aakash H. Chandarana. I am the Regional Vice President for Rates and Regulatory Affairs for Northern States Power Company-Minnesota (NSPM or Xcel Energy or the Company). In this role, I am responsible for NSPM's regulatory filings with the utility commissions in Minnesota, North Dakota, and South Dakota, including proceedings related to rates, resource planning, and service quality filings.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. Prior to joining Xcel Energy, I was a partner at the Briggs and Morgan, P.A. law firm. My practice focused on the energy industry, primarily the state and federal regulation of utilities. I represented utilities in commercial transactions involving generation interconnection agreements, power purchase agreements, and other related types of transactions. I also assisted my clients in regulatory proceedings, including state electric rate cases, and transmission interconnection disputes at the Federal Energy Regulatory Commission.

In 2013, I joined Xcel Energy as its Lead Assistant General Counsel – Regulatory North. In that role, I was the lead regulatory attorney for the Company's operations in Minnesota, North Dakota, South Dakota, Wisconsin, and Michigan. In January 2015, I assumed my current role. Exhibit___(AHC-1), Schedule 1 summarizes my qualifications.

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

A. The purpose of my testimony is to provide background on the resources at issue in this proceeding and demonstrate that each such resource should be recovered (or continue to be recovered) from our South Dakota customers through the Fuel Clause Rider (FCR).

Q. DO YOU HAVE ANY INITIAL OBSERVATIONS REGARDING STAFF'S MOTION TO SHOW CAUSE?

A. Yes. At the outset, I would like to note that Staff's Motion to Show Cause appears to move significantly beyond the scope of the Company's FCR filing from November 2016, and seeks to review resources that are already being recovered through the FCR and have been for some time. This causes concern to the extent it foretells a change in the way South Dakota has historically valued the integrated system. To that end, and because there has been significant changes in the industry over the last decade, we are introducing testimony in this docket about the quantitative and qualitative benefits of the integrated system—and what that means to South Dakota.

Q. PLEASE EXPLAIN.

A. Generally, most of the resources at issue in this proceeding are outside the scope of the Company's request to include the Marshall Solar Power Purchase Agreements (PPAs) in the FCR. In fact, setting aside the three solar resources at issue (the Marshall, North Star and Aurora PPAs), the Motion to Show Cause challenges 26 generating resources of the NSP System—ranging from wind and solar resources to biomass facilities and natural gas plants—all of which have been recovered from the Company's South Dakota customers for years. Additionally, two resources, the Mankato Energy Center combined cycle PPA

(MEC I) and the Cannon Falls combustion turbine (CT) generating facility PPA (Cannon Falls), are capacity resources whose main contract costs - capacity payments - the Company has been recovering in base rates for eleven and nine years, respectively. Consequently, in my view, though the solar resources challenged in this docket served as an entry point for Staff's inquiry, the breadth of the other targeted resources raises more general concerns about how South Dakota values the integrate system; making now the right time to engage in a broader discussion about its many benefits.

Q. HOW IS THE BROADER SYSTEM IMPACTED BY THIS INQUIRY?

A. The NSP System is a large (approximately 10,000 MW) electric system that we believe provides material benefits through economies of scale to all of the customers served by it. Our South Dakota customers make up about five percent (approximately 500 MW) of the NSP System while our Minnesota customers make up approximately 75 percent (approximately 7,500 MW) of the NSP System. Because of this imbalance, our South Dakota customers benefit from a system that is outsized for its actual energy and capacity needs and whose scope is primarily driven by Minnesota. The primary system benefits that flow to South Dakota include valuable hedges against fuel variability, geographic changes, supply dynamics and future market uncertainty. The demands of the system also result in substantial investment opportunities for the state—as with the proposed wind development in Codington, Deuel and Grant County that is valued at over one billion dollars.

South Dakota also benefits from our operational expertise and extensive experience operating within the context of a complex regional marketplace with evolving dynamics. These evolving dynamics have impacted and will continue to impact the types of resources we add to our system, the timing of those additions and how they are utilized. The Company understands these market forces and has long and deep experience—and commits significant resources—to understanding and anticipating emerging trends in the energy industry and how to position ourselves in the future for the benefit of our customers. In that way, each resource decision is built upon the ones that came before it.

In short, we believe that because South Dakota benefits from its inclusion in a large, diverse system, it is reasonable to ask that our South Dakota customers pay their portion of the costs.

Q. WHY IS THE LARGER CONTEXT OF THE INTEGRATED SYSTEM IMPORTANT?

A. Excluding the MEC I and Cannon Falls PPAs (which are capacity resources), the resources at issue make up less than five percent of the Company's installed capacity and less than five percent of the Company's overall energy production. In other words, this hearing is singling out resources at the margins of our system.

Over the past decade, the North Dakota Public Service Commission (NDPSC) has taken a resource-by-resource approach, singling out certain generation resources for disallowance. We believe that this approach has resulted in North Dakota undervaluing the benefits of the integrated system and has created an unsustainable framework. Moreover, while we have spent considerable time searching for an equitable solution that would allow our North Dakota jurisdiction to remain part of the NSP System, we have been unable to identify such a solution. See Exhibit___(AHC-1), Schedule 2. As a result, in our Resource Treatment Framework (RTF) filing, we have advocated for the full legal separation of our North Dakota jurisdiction. In our RTF filing, we have left open the possibility that South Dakota may elect to separate from the system.

Q. ARE YOU SUGGESTING THAT THE COMMISSION MUST ACCEPT ALL RESOURCES THAT THE COMPANY ADDS TO THE NSP SYSTEM?

A. No. The Company has an obligation to demonstrate to the Commission that all resources serving our South Dakota customers are prudent, economical and efficient. In making that showing, we ask the Commission to consider the value the NSP System delivers as a whole. I recognize that reasonable minds can differ with respect to a single resource. It is our hope that those differences are few and that they are shown to be insignificant in comparison to the value delivered by the system as a whole.

However, we view the wholesale disallowance of 29 generation resources as something different. Taking a comprehensive look at the various resources at issue in this proceeding raises fundamental issues of how South Dakota should participate in the NSP System. The remainder of my testimony will address the Motion to Show cause and demonstrate that the resources identified are prudent, economical, and efficient parts of the NSP System.

Q. HOW IS THE REMAINDER OF YOUR DIRECT TESTIMONY ORGANIZED?

A. In the Overview Section, I walk through the resources at issue in this proceeding, and the standards that are applicable to the Commission's review.

In the next section, I discuss the resources for which the Company has been already recovering its costs in South Dakota, what I call the "Historical Resources." I describe these resources, provide context around their acquisition, and explain that they are prudent, economical and efficient in the context of the larger NSP System.

In Section IV, I turn to the large-scale solar resources identified in the Motion to Show Cause—Aurora, North Star and Marshall. I describe the acquisition process that led to the selection of the each project and explain that, within the context of the larger NSP System, each resource is a prudent, economical, and efficient addition that is properly recovered from South Dakota customers.

II. OVERVIEW

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

A. In this section of my Direct Testimony, I discuss how Xcel Energy provides service to our South Dakota customers through the NSP System. I then discuss the various generating resources raised in the Motion to Show Cause. Last, I discuss the standard that governs this proceeding.

A. Service to South Dakota from the NSP System

Q. PLEASE DESCRIBE THE NSP SYSTEM.

A. The Company is a wholly-owned operating subsidiary of Xcel Energy Inc. that owns and operates, in conjunction with its affiliate Northern States Power Company–Wisconsin (NSPW), the integrated system of generation and transmission assets that serves approximately 1.6 million electric customers in Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin (the NSP System). The NSP System developed over many years: as the electric power needs of its customers grew and evolved, the Company undertook various large-scale investments to serve them. And the NSP System continues to evolve in response to supply dynamics, the changing needs of our customers and as generation resources are added and removed from the system. Company Witness Mr. Philip Joseph "P.J." Martin further describes the NSP System, its development, and its evolution to meet the challenges of the future.

Q. WHY DO YOU REFER TO THE NSP SYSTEM AS "INTEGRATED"?

A. Each resource in the NSP System—whether generation or transmission—was developed in consideration of the whole, balancing the need for diversity and hedges against supply and cost volatility.

Q. HOW DOES INTEGRATION INFLUENCE THE COMPANY'S RESOURCE PLANNING?

A. Planning for, and managing, the integrated NSP System is highly complex and requires us to balance the needs and priorities of all of the jurisdictions we serve. We strive to consider the goals of each jurisdiction when planning. Additionally, we are obligated to meet the regulatory requirements of each jurisdiction, including South Dakota, which—as a practical matter—means that the state with the most stringent requirements sets the bar for our compliance.

Q. HAS THE COMPANY FOLLOWED A SET OF GUIDING ASSUMPTIONS AS IT DEVELOPED THE NSP SYSTEM?

A. Yes. Our management of the integrated NSP System has been informed by the following concepts for many years:

- Planning should be done on an integrated basis, because this captures economies of scale, ensures that the risks and costs to any single jurisdiction are mitigated, and allows diversity of energy supply, which contributes to system reliability and price control.

- Respect the sovereign nature of each of the states where we serve, and ensure that regulators understand the costs and risks associated with their decisions.
- Ensure that the Company has an opportunity to fully recover its cost of service in each state served by the NSP System.

Q. HOW DOES THE COMPANY'S SOUTH DAKOTA SERVICE TERRITORY FIT INTO THE NSP SYSTEM?

A. The Company's South Dakota service territory is physically and electrically contiguous to the rest of the Company's service area in Minnesota, and Wisconsin. This is in contrast to the isolated load of our North Dakota jurisdiction.

Q. ARE THERE ADVANTAGES TO THE INTEGRATED GENERATION PORTFOLIO THAT COMPRISES THE NSP SYSTEM?

A. Yes. The NSP System's size and scope provides value through economies of scale, reliability, and fuel diversity. The development of the NSP System and these current and historic benefits is discussed in the Direct Testimony of Mr. Martin.

In addition to these historic benefits, the size and scope of the NSP System positions us well for today's market-based dispatch and the impacts of newer, zero marginal cost technologies coming online. Our size means that capacity and energy needs are likely to be sufficiently large to support building new generating stations rather than having to purchase smaller increments of capacity and energy on the market. Our ability to supply all of our energy needs provides a hedge against current and future market risk.

B. Resource Identified in the Motion to Show Cause

Q. WHAT RESOURCES HAVE BEEN CHALLENGED IN THIS PROCEEDING?

A. The Commission's May 25, 2017 Order required the Company to present evidence as to why it should be permitted cost recovery for several different groups of resources. I have grouped these resources into two main categories, and several sub-categories.

The first category is the new Solar Resources that the Company is adding to the NSP System. The Solar Resources include the Aurora Solar, Marshall Solar and North Star Solar projects. I note that while the Company has sought recovery of the Marshall project through the FCR, it has not yet requested recovery of the Aurora or North Star projects. Still, in anticipation of the Company seeking such recovery, the Staff sought to include the projects in the current investigation. I provide additional information regarding the Solar Resources in Exhibit___(AHC-1), Schedule 3 of my Direct Testimony.

The second category is comprised of power purchase agreements (PPAs) for which the Company has long been recovering its costs in South Dakota, what I refer to as the Historic Resources. These Historic Resources are comprised of three separate groupings: (1) Community-Based Energy Development PPAs (the C-BED Projects); (2) PPAs for projects that were funded in whole, or in part, by the Renewable Development Fund (the RDF Projects); and (3) resources identified as having an average cost of more than $100/MWh (the Other PPAs). Of the Other PPAs, two are capacity resources (the Capacity PPAs) acquired through competitive bidding to meet an identified capacity need, and three are biomass resources (Biomass PPAs). Table 1 below identifies the Historic Resources, their size, fuel type, program as well as contract beginning and end dates. I provide additional information regarding the C-BED Projects in Exhibit___(AHC-1), Schedule 4, RDF Projects in Exhibit___(AHC-1), Schedule 5, and the Capacity PPAs and Biomass PPAs in Exhibit___(AHC-1), Schedule 6 of my Direct Testimony.

Table 1

Historic Resources

PPA Counterparty Name		Program	Fuel Type	Year of Petition/ Contract	Commercial Operation Date	Termination Date (COD + PPA Term)	Fuel Clause Components (U)
Adams Wind Generations		CBED	Wind	2009	3/9/2011	3/8/2031	Energy
Big Blue Wind Farm, LLC		CBED	Wind	2010	12/31/2012	12/30/2032	Energy
Carleton College		RDF	Wind	2003	9/20/2004	9/19/2024	Energy
Danielson Wind Farms, LLC		CBED	Wind	2009	3/11/2011	3/10/2031	Energy
Ewington Energy Systems, LLC		CBED	Wind	2006	5/28/2008	5/27/2028	Energy
Grant County Windfarm, LLC		CBED	Wind	2009	8/9/2010	8/8/2030	Energy
Hilltop Power, L.L.C.		CBED	Wind	2007	2/20/2009	2/19/2029	Energy
Jeffers Wind Energy Center		CBED	Wind	2006	10/10/2008	10/9/2028	Energy
North Community Turbines LLC		CBED	Wind	2010	5/28/2011	5/27/2031	Energy
North Wind Turbines LLC		CBED	Wind		5/28/2011	5/27/2031	Energy
Ridgewind Power Partners, LLC		CBED	Wind	2008	1/13/2011	1/12/2031	Energy
Uilk Wind Farm, LLC		CBED	Wind	2008	1/15/2010	1/14/2030	Energy
Valley View Transmission		CBED	Wind	2008	11/30/2011	11/29/2031	Energy
Winona County Wind LLC		CBED	Wind	2009	10/27/2011	10/26/2031	Energy
Woodstock Municipal Wind, LLC		CBED	Wind	2009	6/24/2010	6/23/2030	Energy
Zephyr Wind LLC		CBED	Wind	2011	12/26/2012	12/25/2032	Energy
PPA Counterparty Name		Program	Fuel Type	Year of Petition/ Contract	Commercial Operation Date	Termination Date (COD + PPA Term)	Fuel Clause Components (U)
Best Power International LLC (RDF)							
	St. Johns	RDF	Solar	2009	5/27/2010	5/26/2030	Energy
	Sr. Notre Dame	RDF	Solar	2014	12/1/2015	11/29/2030	Energy
Diamond K Dairy Inc.		RDF	Biomass	2010	1/1/2015	12/30/2024	Energy
Slayton Solar, LLC		RDF	Solar	2010	1/1/2013	12/31/2032	Energy
St. Olaf College		RDF	Wind	2006	10/6/2008	10/5/2028	Energy
PPA Counterparty Name		Program	Fuel Type	Year of Petition/ Contract	Commercial Operation Date	Termination Date (COD + PPA Term)	Fuel Clause Components
Benson Power, LLC (aka Fibrominn)		Biomass	Biomass	2000	9/11/2007	9/9/2028	Energy (V)
Cannon Falls Energy Center		Capacity	Natural Gas	2005	4/11/2008	4/10/2025	Energy (W)
Laurentian Energy Authority, L.L.C.		Biomass	Biomass	2005	1/1/2007	12/31/2026	Energy (X)
Mankato Energy Center, L.L.C.		Capacity	Natural Gas	2004	1/1/2006	12/31/2025	Energy (Y)
St. Paul Cogeneration		Biomass	Biomass	1998	4/13/2003	4/12/2023	Energy (Z)

(U) Wind - Energy and wind curtailment payments, when provided for in the PPA, are includes in the FCA.

(V) Benson - Energy Payment rate is included in the FCA. No capacity charge. The FCA also collects payment provision for reimbursement payment of fuel

(W) Cannon Falls Energy Center - Energy Payment rate is included in the FCA, which also includes turbine start payments. Capacity payment is covered through rate based.

(X) Laurentian Energy Authority - Energy Payment rate is included in the FCA. No capacity charge. The FCA also collects payment provision for reimbursement

(Y) Mankato Energy Center - Energy Payment rate is included in the FCA, which also includes turbine start payments. Capacity payment is covered through rate based.

(Z) St. Paul CoGen - Energy Payment rate, no capacity charge. The FCA also collects payments related to cogeneration, condensing, production, and interconnection.

Q. WHAT ARE COMMUNITY-BASED ENERGY DEVELOPMENT PROJECTS?

A. C-BED Projects are wind generating facilities that were developed pursuant to Minnesota's then effective C-BED Statute (Minn. Stat. § 216B.1612, repealed in 2016). The C-BED statute provided a series of requirements to qualify for C-BED status, required that Minnesota utilities evaluate C-BED projects as part of their resource planning, and required utilities to develop a C-BED tariff. Generally, the Minnesota C-BED program was intended to help support wind development in the state. Under the auspices of the C-BED program, the Company entered into 20-year PPAs with several C-BED projects that were offering (what was then) cost competitive pricing. These projects tended to be relatively small and were part of the Company's early wind acquisition efforts.

Q. WHAT IS THE RENEWABLE DEVELOPMENT FUND?

A. The RDF was created as part of comprehensive legislation that authorized additional storage of spent nuclear waste – effectively extending the lives of Xcel Energy's nuclear facilities (1994 Minn. Sess. Law, Ch. 641). The RDF exists for the purpose of developing renewable sources of electricity, such as wind, solar, and biomass. Pursuant to statute, Xcel Energy is required to fund the RDF under a formula tied to the amount of dry cask storage at each of the Company's nuclear generating facilities. The RDF provides support for several programs, including a grant program administered by Xcel Energy which funds – in whole or in part – small scale energy production facilities intended to provide the Company experience with newer generation technologies. Consistent with the settlement of the Company's 2009 electric rate case (Docket No. EL09-009 and the Commission's January 12, 2010 Order, no costs for funding the RDF are recovered from South Dakota customers.

Q. ARE THE BIOMASS PROJECTS RELATED TO THE COMPANY'S NUCLEAR FLEET AS WELL?

A. Yes. In addition to creating the RDF, the 1994 Prairie Island Cask Storage Authorization Act also established a biomass mandate in Minnesota. Pursuant to the original legislation, the Company was required to add 125 MW of installed capacity generated by "farm grown closed-loop biomass". In 2003, the Minnesota State legislature amended the biomass mandate and effectively reduced it from 125 MW to 110 MW (Minnesota Stat. § 216B.2424, Subd. 5.a.). As the only utility which owns nuclear power plants in Minnesota, and consistent with the relationship between this requirement and continued operation of our nuclear fleet, the Biomass Mandate (like the RDF) is applicable only to Xcel Energy.

Q. HAS THE BIOMASS MANDATE BEEN RECENTLY AMENDED?

A. Yes. In the last Minnesota State legislative session, the Biomass Statute was amended again to allow the Minnesota Public Utilities Commission (MPUC) to approve the premature termination of biomass PPAs—either through early termination agreements or through agreements for the purchase and closure of the facility. The Company supported this legislation to provide statutory certainty for our recent biomass related customer cost-savings initiative.

Q. WHAT IS THE COMPANY'S CUSTOMER COST-SAVING INITIATIVE?

A. We have been exploring ways to address the biomass PPAs—some of our highest-cost contracts on the NSP System—given that it appears unlikely that this technology will mature into a cost effective generation product. We have now entered into a series of four transactions to terminate or restructure PPAs with Benson Power, the Pine Bend biogas facility, and the Hennepin Energy

Recovery Center (HERC). We are also negotiating a potential termination of the Laurentian PPA. If all of these transactions are completed and approved, these initiatives would save our customers over $400 million on a net present value basis.

Q. HOW DOES THE COMPANY'S CUSTOMER COST-SAVING INITIATIVE IMPACT THE MOTION TO SHOW CAUSE?

A. One PPA that is addressed in our customer cost-savings initiative is also identified in the Motion to Show Cause—Benson Power. Regarding Benson Power, the Company is seeking to terminate the PPA with Benson Power, LLC, acquire the Benson Power biomass plant, and subsequently close the facility. We are also negotiating with Laurentian Energy Authority regarding the Laurentian PPA to buy-out the existing PPA.

If these transactions move forward, we would expect to seek recovery of the transaction costs from our South Dakota customers so that they can enjoy the savings from these transactions. These transactions would also materially moot the need for Commission review of these PPAs in this proceeding.

Q. ARE THERE OTHER ITEMS APPLICABLE TO THE RESOURCES AT ISSUE IN THIS PROCEEDING?

A. Yes. In 2014, the Minnesota legislature established the Solar Energy Standard (Minnesota Stat. § 216B.1691, Subd. 2.f.), which requires that at least 1.5 percent of a utility's total retail electric sales to retail customers in Minnesota be generated by solar energy by 2020 and sets a goal of ten percent by 2030.

C. Standard for Analysis

Q. WHAT STANDARD SHOULD THE COMMISSION APPLY IN ITS REVIEW OF THE CHALLENGED RESOURCES?

A. Under South Dakota law, the burden is on the utility to "establish that the underlying costs of any rates, charges, or automatic adjustment charges filed under this chapter are prudent, efficient, and economical and are reasonable necessary to provide service to the public utility's customers in this state." (SDCL 49-34A-8.4)

The Commission has found that "this standard provides … a certain amount of flexibility to pick alternatives that are best for the overall system, not strictly the least-cost alternative."[1] The Commission has further held that the standard for testing cost recovery requires consideration of "[o]ther factors, such as fuel diversity and diversification of risk." Moreover, with respect to when prudence is measured, the Commission has explained that it is the facts and circumstances available "at the time the decision to proceed with such resource addition was made" that govern.[2]

Taken together, the South Dakota standard asks the Commission to put itself in the shoes of the Company at the time the resource decision was made and, equally as important, permits the Commission to look beyond a strict least-cost plus need paradigm when evaluating prudence.

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[1] *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase its Electric Rates*, Docket No. EL11-019, FINAL DECISION AND ORDER; NOTICE OF ENTRY at 7 (July 2, 2012).

[2] *In the Matter of the Application of Black Hills Power, Inc., for Authority to Increase its Electric Rates*, Docket No. EL09-018, FINAL DECISION AND ORDER GRANTING JOINT MOTION FOR APPROVAL OF SETTLEMENT STIPULATION AND APPROVING RATES AND TARIFFS; NOTICE OF ENTRY at 24 (Aug. 11, 2010).

III. HISTORIC RESOURCES

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

A. In this section of my Direct Testimony, I discuss the Historic Resources and why—consistent with past practice—the Commission should continue to allow the Company to recover their costs from our South Dakota customers.

Q. ARE THE HISTORIC RESOURCES PROVIDING CAPACITY AND ENERGY USED TO SERVE THE COMPANY'S SOUTH DAKOTA CUSTOMERS TODAY?

A. Yes. The Historic Resources are used and useful for the provision of electric service. The oldest Historic Resource began its commercial operations in 2003, and the newest resource began its commercial operation in 2015.

Q. HAS THE COMPANY BEEN RECOVERING THE COSTS OF THE HISTORIC RESOURCES IN SOUTH DAKOTA THROUGH THE FCR?

A. Yes. Each and every one of the Historic Resources has been recovered in South Dakota rates. The majority of the Historic Resources are priced as energy only and therefore all of their costs are being recovered through the FCR. For those Historic Resources whose contracts have a capacity charge component (MEC I and Cannon Falls), the Company has been recovering the capacity costs in base rates while the energy charges flow through the FCR.

Q. IS IT REASONABLE FOR THE COMMISSION TO SUDDENLY DISALLOW THE COSTS OF THE HISTORIC RESOURCES?

A. No, it isn't. Of the 26 projects that comprise the Historic Resources, all but three have been recovered by the Company for at least five years, with many costs being recovered for almost a decade. It would be unreasonable for the

Commission to disallow the costs of resources that have been serving the system for a material amount of time.

Q. WHY DOES THE AMOUNT OF TIME THAT ELAPSED MATTER?

A. While I recognize that the Commission may revisit the costs of the Historic Resources, re-examining resources for which the Company has a long history of recovery materially impacts the certainty the Company needs to plan for the NSP System. Resource decisions are long-term, with many PPAs lasting 20 years. If the Commission sets a standard to revisit resource decisions years after recovery has begun, it would encourage the Company to make shorter-term resource decisions which provide different (and potentially less) value to our customers.

We have historically assumed that once initial recovery has begun, it will continue. That certainty allows us to operate the system as a coherent whole. While disallowances *prior to* recovery are disruptive—at least the disallowing jurisdiction provides a timely signal that can inform the Company's future resource decisions. Conversely, disallowing resources that have enjoyed cost recovery for years provides no such signal and materially impairs our ability to plan the system with any reasonable degree of confidence. I believe that such a result is unreasonable and calls into question our ability to manage the system on a going forward basis.

A. The Community-Based Energy Development Projects

Q. PLEASE DESCRIBE THE ROLE OF THE C-BED PROJECTS IN THE NSP SYSTEM.

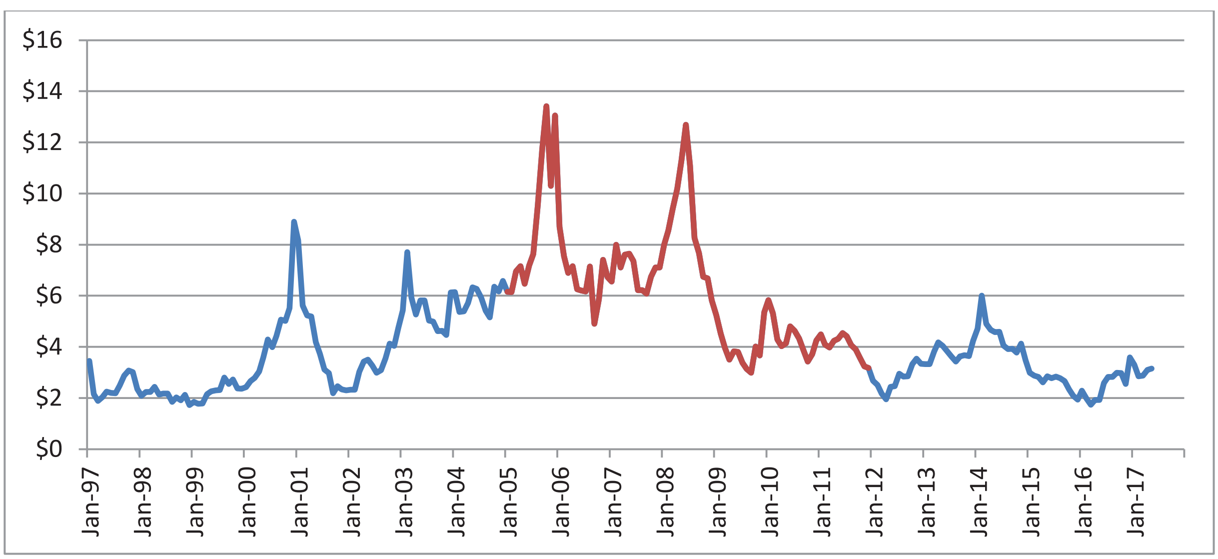
A. The individual C-BED Projects range in size from 0.75 MW to 50 MW in nameplate installed capacity, and their dates of commercial operation fall between 2008 and 2012. At approximately two percent, the C-BED Projects also contribute a very small percentage of the overall energy produced by the system, with the smallest C-BED Project producing 0.008 percent and the largest C-BED Project producing 0.38 percent.

Q. WHY DID THE COMPANY ACQUIRE THE C-BED RESOURCES?

A. As I noted above, the C-BED Projects were brought online over a period of years from 2008 to 2012. The Company acquired these resources pursuant to the statutory C-BED program but also to provide resource diversity. As shown in Figure 1, below, gas prices in the 2006-2011 timeframe were materially higher than the current market price; gas prices were also more volatile than we are experiencing today.

Figure 1

Historic Gas Prices (Henry Hub)



Source: EIA

Accordingly, the Company believed that a prudent, economic, and efficient way to manage its system management was to hedge its commodity risk by diversifying the NSP System at the time that wind was an emerging technology. I note that the Commission recognized the value of fuel diversification in approving the Company's Nobles wind project and that rationale holds here. I also note that pricing for the C-BED projects was reasonably competitive with wind pricing at that time considering the purpose of the C-BED program.

Q. CAN YOU PROVIDE FURTHER EVIDENCE THAT THE C-BED PROJECTS WERE REASONABLY COMPETITIVE WITH OTHER WIND PRICING, AS YOU SUGGEST?

A. The C-BED PPAs arose during a time (2006-11) of substantially escalating capital costs of wind power.[3] The C-BED PPAs were procured using competitive bidding processes or were otherwise evaluated against competing proposals and reflect escalating prices within a reasonable range as other wind projects purchased in that same timeframe.[4] Additionally, the C-BED PPAs are within a reasonable range of the Nobles and Grand Meadows projects, which were Company-owned wind farms procured in a similar timeframe. I believe that these data points support the suggestion that C-BED wind was reasonably priced at the time.

Q. IS THE SIZE OF THE C-BED PROJECTS AND THE FACT THAT THE COMPANY ACQUIRED THESE WIND PROJECTS WHEN WIND WAS AN EMERGING TECHNOLOGY RELEVANT TO THE COMMISSION'S ANALYSIS?

A. Yes, I believe so.

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[3] *The Past and Future Cost of Wind Energy,* May 2012, National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory.

[4] Exhibit___(AHC-1, Schedule 7) summarizes the history of the C-BED procurement processes.

Q. PLEASE EXPLAIN.

A. At the time that the C-BED Program was ongoing, the Company committed to obtain 500 MW (nameplate) of C-BED wind, making up approximately half a percent of the overall accredited capacity of the NSP System under the then-effective MISO accreditation standards. In the end, however, we acquired only 277 MW (nameplate) of C-BED projects representing a little more than half as much capacity. During this period, the Company viewed the C-BED Projects as an opportunity to develop expertise in the fast emerging wind energy sector. Specifically, we gained valuable experience with the following: negotiating renewable energy purchase contracts; understanding community-based energy development; developing practical knowledge of FERC's relatively new interconnection requirements; and, most importantly, integrating wind resources and understanding and mitigating the operational effects of intermittent resources on the NSP System.

Obtaining this experience has been invaluable, as wind has become a cost-competitive, mature generating resource. For example, the breadth and depth of our operational experience integrating wind resources has placed us well ahead of our peers in this area. Additionally, the experience we obtained negotiating many small wind PPAs helped us develop the expertise to quickly identify and negotiate new contracts upon the extension of the federal Production Tax Credits. This gives us the ability to act nimbly in an ever-changing market place. Our experience navigating FERC and MISO's interconnection rules has helped us develop the expertise to manage our own projects as well as evaluate the interconnection risks of our counterparties. Moreover, South Dakota is poised to materially benefit from the real world experience gained—at least in part—from our C-BED experience. The Company has proposed a 600 MW wind project, sited in South Dakota, that we estimate will deliver more than one billion dollars of investment to the state.

Q. WHY IS GAINING THIS EXPERIENCE WITH WIND RESOURCES SO IMPORTANT?

A. As I mentioned earlier, the NSP System provides benefits to our customers by, in part, being sufficiently large to develop a broad and diverse array of generating resources from all fuel types. While it is still important to consider all available technologies when circumstances warrant, gaining experience with wind and other emerging technologies provides us more options to meet our customers' needs than if we were to only utilize historic thermal fuels. I stress that this does not mean that all new resources must be renewable resources. For example, maximizing existing interconnection rights, such as what we did at our Black Dog site for the new Unit 6 and Sherco for our new combined cycle facility, are also key determinations. However, gaining experience with emerging technology is a worthwhile endeavor, not only for wind but for all resource types, as I discuss below.

Q. ARE THE COSTS OF THE C-BED PROJECTS PRUDENT, EFFICIENT, AND ECONOMICAL, AND ARE THEY REASONABLE AND NECESSARY TO PROVIDE SERVICE TO THE COMPANY'S SOUTH DAKOTA CUSTOMERS?

A. Yes. The C-BED Projects were competitively-priced, small wind projects that provided the Company important fuel diversity and system hedging at a time of high, volatile gas prices while also providing the Company with early experience procuring, managing and operating an emerging technology. Our experience with the C-BED program has helped us to become a leader in wind technology—a resource that provides (and will continue to provide) material economic benefits to our customers. Even though the C-BED Projects were supported by a Minnesota legislative program, that fact should not detract from the important role these resources have played in the development of our system. For all of these reasons, I believe the C-BED resources meet the Commission's standard for recovery.

B. The Renewable Development Fund Projects

Q. PLEASE DESCRIBE THE ROLE OF THE RDF PROJECTS IN THE NSP SYSTEM.

A. Like the C-BED Projects, the RDF Projects make up a very small percentage of our overall system resources—indeed, less than 0.02 percent. The individual RDF Projects range in size from .35 MW to 1.66 MW in nameplate installed capacity, and their dates of commercial operation fall between 2004 and 2015. At 0.04 percent, the RDF Projects also contribute a very small percentage of the overall energy produced by the system, with the smallest RDF Project producing 0.001 percent and the largest RDF Project producing 0.015 percent.

Q. WHY DID THE COMPANY ACQUIRE THE RDF PROJECTS?

A. Pursuant to its enabling statute, the goal of the RDF Program is to promote the development of emerging renewable technologies. The RDF Program grew out of a legislative compromise that was struck in 1994 and allowed the Company to continue its nuclear operations. South Dakota has historically been a steadfast supporter of nuclear power and, presumably, the bargain that was struck to retain it. For that reason, I was surprised to see both the RDF and biomass resources placed at issue in this proceeding.

That said, the RDF—like C-BED—has provided the Company with valuable experience in emerging renewable technologies. For example, the St. Johns and Sisters of Notre Dame projects provided opportunities to develop innovative interconnection and metering arrangements for solar installations. Likewise, the Slayton Solar project provided the Company with experience integrating solar resources on an operational level as well as highlighting the interconnection challenges that are unique to solar projects. The operational and transactional experience gained in the RDF space has informed our approach to larger-scale renewable technologies.

Q. IS THE SIZE OF THE RDF PROJECTS AND THE FACT THAT THE COMPANY ACQUIRED THESE PROJECTS TO GAIN EXPERTISE IN EMERGING TECHNOLOGIES RELEVANT TO THE COMMISSION'S ANALYSIS?

A. Yes, I believe so. Taking a small slice of the NSP System to test emerging technologies and learn how to effectively operate, integrate and otherwise leverage these new technologies is an important part of maximizing the value of the overall NSP System—and will continue to be as storage (and other) technologies continue to evolve and mature. Utilizing the economies of scale that the NSP System provides gives Xcel Energy the ability to spread these proportionally small costs over a very large customer base so that the Company can continue to be a leader in capturing the benefits of new technologies on behalf of our customers. For all of these reasons, I believe the RDF resources meet the Commission's standard for recovery.

C. The Other Power Purchase Agreements

Q. PLEASE DESCRIBE THE ROLE OF THE OTHER PPAS IN THE NSP SYSTEM.

A. As I mentioned earlier, the Other PPAs are comprised of two groups of resources, the Capacity PPAs and the Biomass PPAs. Each fulfills a different role in the NSP System.

Before jumping into a description of each category, I will note that Staff appears to have selected these resources by setting an arbitrary threshold of $100/MWh and placing at issue any resource that exceeds that amount. Commission precedent does not support such an indiscriminate approach, particularly where—as here—the resources at issue have been recovered from South Dakota customers for nearly a decade.

MEC I is a 375 MW combined cycle plant in Mankato, Minnesota that was selected through a competitive bidding process initiated in 2001. It accounts for approximately three percent of the NSP System's overall accredited capacity and produces less than two percent of the NSP System's overall energy. Under the terms of the PPA for MEC I, the Company makes capacity payments to the plant owners (which are recovered in base rates in South Dakota) and also makes separate energy payments (which are recovered in the FCR in South Dakota) under a tolling arrangement where the Company makes small payments to the project owners to cover their variable costs of converting Xcel Energy's natural gas into electricity.

Cannon Falls is an approximately 357 MW (winter) combustion turbine generating facility. It accounts for approximately three percent of the NSP system's overall accredited capacity and produces less than two percent of the NSP System's overall energy. The Cannon Falls PPA was selected as part of the same 2001 all source RFP from which MEC I was chosen. Much like the MEC I PPA, the Cannon Falls PPA is structured to require capacity payments as well as a tolling charge for energy.

The Biomass PPAs are biomass fueled resource acquired by the Company from 1998 to 2005, consistent with the Biomass Mandate that emerged from the legislative compromise that allowed the Company to continue its nuclear operations. Unlike MEC I and Cannon Falls, the Biomass PPAs are priced as energy only even though these resources operate at very high capacity factors. The Biomass PPAs provide a total of 115 MW of nameplate capacity. They account for approximately one percent of the NSP System's overall accredited capacity and produce approximately two percent of the NSP System's overall energy.

Q. CAN YOU ELABORATE ON YOUR CONCERNS WITH THE METHODOLOGY USED TO PLACE THE OTHER PPA RESOURCES AT ISSUE?

A. Yes. Setting an arbitrary threshold that assumes a resource is "too expensive" does not give credence to the facts surrounding that resource's acquisition or the benefits that resource contributes to the system. As I noted earlier, in the early to mid-2000s, gas prices were on the rise. The upward projections in conjunction with the volatility of gas prices informed our desire for a fuel hedge and, ultimately, led us to pursue the Capacity PPAs at issue here. That the price of gas has steadily decreased in recent years does not make that historical decision imprudent. Under the governing standard, the Commission must evaluate prudence at the time the decision was made—without the benefit of hindsight.

Q. IS THERE ANYTHING PARTICULARLY CONCERNING TO YOU ABOUT THE INCLUSION OF THE MEC I AND CANNON FALLS PPAS?

A. Yes, I am particularly concerned that the Staff used the combined capacity and energy payments of the MEC I and Cannon Falls PPA to evaluate the costs of the resource compared to the $100/MWh threshold. First, doing so conflates two lines of payments that are recovered separately, one in base rates (capacity) and one in the FCR (energy). This methodology also fails to account for the fact that these resources are dispatchable, unlike wind and solar, and therefore are important capacity resources rather than predominantly energy resources. It also fails to capture the resource planning impetus behind placing combined cycle and combustion turbine resource on the system and lacks the historical foundation for resource review that created the all source RFP which resulted in these projects.

Q. DO THE CAPACITY AND ENERGY CHARGES FLOW THROUGH THE FUEL CLAUSE?

A. No. Only the energy charges flow through the fuel clause. There may have been a misunderstanding regarding the levelized cost calculations for these resources provided in response to Commission Staff data requests. For 2016, the fuel clause related costs of the MEC 1 and Cannon Falls PPAs were approximately $26 per MWh and $48 per MWh, respectively.[5]

Q. ARE THE COSTS OF THE CAPACITY PPAS PRUDENT, EFFICIENT, AND ECONOMICAL, AND ARE THEY REASONABLE AND NECESSARY TO PROVIDE SERVICE TO THE COMPANY'S SOUTH DAKOTA CUSTOMERS?

A. Yes. The Cannon Falls and MEC I PPAs have been serving the NSP System for over a decade. They are the result of an all source-RFP and represent competitive pricing for gas fired combined cycle and combustion turbine generators at the time.[6] No circumstances have arisen that would call into question these resources. Additionally, setting an arbitrary $100/MWh threshold and combining the capacity and energy payments to push these resources above

[5] Exhibit___(AHC-1, Schedule 6).

[6] Exhibit___(AHC-1, Schedule 8) summarizes the history of the MEC 1 and Cannon Falls PPA procurement processes.

that threshold does not present a reasonable analytical framework under which to evaluate the resources—and it certainly does not support their removal from the FCR.

Q. PLEASE DESCRIBE THE ROLE OF THE BIOMASS PROJECTS IN THE NSP SYSTEM.

A. The Biomass Projects provide approximately one percent of capacity and two percent of energy of the NSP System, and that percentage is likely to shrink significantly in the near term. As outlined above, we have proposed to remove from our system the Benson Power PPA and are working to negotiate a termination of the Laurentian PPA. I believe this demonstrates that the Company is open to working with our various jurisdictions to remove resources that are not sufficiently beneficial to our customers to justify their cost.

Q. WHY DID THE COMPANY ACQUIRE THE BIOMASS PPAS IN THE FIRST PLACE?

A. The Biomass PPAs—like the RDF Projects—grew out of a legislative compromise that was necessary to support the continued operation of the Company's nuclear fleet. Our nuclear stations have been a mainstay of our generation portfolio for many years. It is important to note that the relationship between the Biomass and RDF Projects, on the one hand, and the viability of our continued nuclear operations, on the other, demonstrate the complex nature of the integrated system and underscore the inequity that results when a jurisdiction attempts to carve off one resource while retaining another.

Q. WERE THERE OTHER REASONS TO MOVE FORWARD WITH THE BIOMASS PROJECTS?

A. Yes. Like wind, biomass was also an emerging technology at the time, and the Biomass Mandate provided the Company with an opportunity to develop experience with this technology. In the end, biomass has proven to be a less successful technology than wind generation, and this fact has led the Company to find ways to minimize its use going forward.

Q. ARE THE COSTS OF THE BIOMASS PPAS PRUDENT, EFFICIENT, AND ECONOMICAL, AND ARE THEY REASONABLE AND NECESSARY TO PROVIDE SERVICE TO THE COMPANY'S SOUTH DAKOTA CUSTOMERS?

A. Yes. Even though biomass technology has been largely eclipsed by wind generation, it was prudent and reasonable for the Company to contract for these resources at the time. First, at that time, it was far from clear what renewable technologies would emerge as the leading technologies of the future. Given that, we made a reasonable investment in understanding the capabilities of biomass—utilizing only a small fraction of our system. Also, critically, the Biomass Projects were part of the price that was paid to secure the future of our nuclear operations—a generation resource long supported by South Dakota. For all these reasons, the Biomass Projects should continue to be recovered from our South Dakota customers.

I also note that two of the three Biomass Mandate contracts – Benson Power and Laurentian – are the focus of the customer cost-savings initiative that I discussed above. By purchasing and closing the Benson facility as well as terminating the Laurentian PPA, we are demonstrating our willingness to recognize evolving system dynamics and leverage our size to benefit NSPM customers.

IV. SOLAR RESOURCES

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

A. In this section of my Direct Testimony I discuss the Solar Resources, the circumstances surrounding their acquisition, and how these resources are prudent, efficient, economical and reasonable and necessary for Xcel Energy's provision of service to our South Dakota customers.

Q. PLEASE DESCRIBE THE SOLAR RESOURCES.

A. The category of Solar Resource is comprised of three separate PPAs: the Aurora Solar PPA; the North Star Solar PPA; and the Marshall Solar PPA. Each PPA is priced as energy only, but the Company also obtains all of the capacity from each of the Solar Resources according to their contract terms.

Aurora Solar Project consists of an up-to 100 MW nameplate dispersed solar project located at up to 24 sites in Minnesota to be interconnected to various Xcel Energy distribution substations. Each phase of the project will be from 2 to 10 MW in size and will take advantage of excess transfer capability at the interconnecting substation. The developer has contractually committed that the project will achieve 71 percent capacity accreditation from MISO, meaning that a 100 MW nameplate plant will provide 71 MW of MISO accreditable capacity. The Aurora Project achieved commercial operation on June 16, 2017, and we expect it produce approximately 0.45 percent of the total energy on the NSP System.

Marshall Solar is a 62.25 MW nameplate utility scale, transmission interconnected, solar energy projected located near Marshall, Minnesota. We expect Marshall Solar to provide 31 MW, or 0.33 percent, of accredited capacity for the NSP System and to produce approximately 0.27 percent of the total energy on the NSP System. Marshall Solar began commercial operation in January 2017.

North Star Solar is a 100 MW nameplate utility scale, transmission interconnected, solar energy project located near North Branch, Minnesota. We expect North Star solar to provide 50 MW, or 0.53 percent, of accredited capacity for the NSP System and to produce approximately 0.45 percent of the total energy on the NSP System. North Star Solar achieved commercial operation in December 2016.

A. Resource Selection Processes

Q. HOW DID THE COMPANY ACQUIRE THESE RESOURCES?

A. The Solar Resources were selected at approximately the same time through two separate processes, both developed by the Minnesota Public Utilities Commission (MPUC). The Aurora Solar Project was selected through a competitive Acquisition Process before the MPUC for the acquisition of up to 500 MW of capacity resources to meet an identified capacity need in the 2017 to 2019 time frame. The North Star and Marshal Solar Projects were selected as part of a larger 187 MW portfolio of Solar Resources (187 MW Portfolio) through a request for proposal for solar projects to meet the Minnesota SES.

Q. ARE THERE SPECIFIC REGULATORY PROCESSES THAT THE COMPANY MUST FOLLOW WHEN SELECTING CERTAIN RESOURCES SUCH AS THE SOLAR RESOURCES?

A. Yes. Each state in which we provide electric service has a different regulatory regime. Two of our states – Minnesota and North Dakota – require that we obtain preapproval of the resources we select. Among other utilities, these requirements are unique to the Company. In Minnesota, the preapproval process was ordered in out 1994 resource planning process to help ensure transparent resource selections consistent with the then-prevailing market conditions (MPUC Docket No. E002/RP-95-589.) In North Dakota, the preapproval requirements were agreed to as part of the settlement agreement concluding our 2008 test year rate case (NDPSC Case No. PU-07-776).

Three of our states – South Dakota, Wisconsin and Michigan – do not put any preconditions on our resource selection, but rely on after-the-fact review in rate cases or other proceedings.

Q. PLEASE SUMMARIZE THE PROCESS THE COMPANY MUST FOLLOW IN MINNESOTA.

A. In Minnesota, most resource acquisitions are reviewed in a two-step process. First, resource needs are determined through the resource planning proceedings before the Minnesota Public Utilities Commission (MPUC). Second, the Company undergoes a MPUC-designed competitive bidding process to select the needed resource(s). Xcel Energy's resource planning is more fully discussed in Mr. Martin's Direct Testimony.

Q. HOW WAS THE COMPETITIVE BIDDING PROCESS DEVELOPED?

A. Xcel Energy has a long history of procuring new generation resources through a variety of competitive processes including competitive bidding to probe the marketplace and create price competition for the acquisition of long-term generating capacity. The Company believes that this is one of the most prudent ways for us to acquire resources and is consistent with Minnesota law.

During our 2004 Resource Plan in Minnesota, the MPUC became concerned about our competitive bidding processes in situations where Xcel Energy was proposing its own resource alternative. The MPUC perceived an inherent conflict of interest where Xcel Energy was both the evaluator and a bidder. As a result of this concern, the MPUC called upon the Company to work with stakeholders to develop a resource procurement process that would be fair and transparent to all stakeholders.

Based on our work with stakeholders, a two-track system was developed that contemplated two different processes—one where the Company is seeking to develop its own generation and another where the Company is soliciting bids from third parties only. This is sometimes referred to as "Track 1" (when no Xcel Energy project is proposed) and "Track 2" (when an Xcel Energy project is proposed). A copy of the MPUC's Order establishing this process is provided as Exhibit___(AHC-1), Schedule 9 to my Direct Testimony.

Q. PLEASE BRIEFLY DESCRIBE THE TRACK 1 PROCESS.

A. Track 1 is used in circumstances where Xcel Energy is not seeking to construct the resource itself. Under Track 1, we proceed through a competitive Request for Proposals (RFP) bidding process. Track 1 has been the primary method we have used to procure new resources.

Q. WERE ANY OF THE SOLAR RESOURCES SELECTED THROUGH THIS TRACK 1 PROCESS?

A. Yes. The Company acquired its 187 MW Solar Portfolio – which includes the Marshall Solar and North Star Solar projects – through the Track 1 Process. The RFP solicitation which produced the 187 MW Portfolio was intended to probe the market for solar resources that could capture the then-effective Federal Investment Tax Credit (ITC) to determine whether the resulting projects would be a cost effective way to meet the Company's SES compliance obligations. I discuss the circumstances surrounding our acquisition of the 187 MW Solar Portfolio later in my Direct Testimony.

Q. PLEASE BRIEFLY DESCRIBE THE TRACK 2 PROCESS.

A. The Track 2 process applies when the Company seeks to meet its identified resource need with a Company-owned, self-build project. For the Track 2 process, the MPUC developed a competitive acquisition process or CAP mechanism which also requires that we file a certificate of need (CON) for the Company-proposed resource. Then, we solicit and evaluate competing proposals from third-party vendors. The competing proposals are evaluated through a contested case process to provide a thorough record on the relative merits of the proposals. This process is intended to help ensure that independent power producers have an opportunity to sponsor alternative proposals to the Company's self-build proposal and that the then-existing market place for resources is thoroughly explored.

The Track 2 process has the following steps:

1. The MPUC approves the resource need to be addressed in the competitive acquisition process through its resource planning order, which establishes parameters around size, type and timing;

2. The Company submits its proposal with the information required in Minnesota rules and statutes governing certificate of need applications;

3. On the same date the Company files its proposal, interested competitors provide their proposals in similar certificate-of-need-like detail, including proposed contract terms;

4. After the MPUC determines that the proposal filings are adequate, a contested case is conducted before an administrative law judge. At the end of the hearing process the administrative law judge provides findings and recommendations to the MPUC;

5. The MPUC considers the developed record, issues its resource selection, and grants any associated certificates of need; and

6. In the event the MPUC selects a power provider proposal rather than the Company's self-build proposal, the Company and selected power provider have four months to negotiate a power purchase agreement and bring it back to the Commission for approval.

Q. WERE ANY OF THE SOLAR RESOURCES SELECTED THROUGH THIS TRACK 2 PROCESS?

A. Yes. The Aurora Solar Project was selected through the Track 2 process as part of a larger basket of resources which included the Company's new 208 MW combustion turbine at our existing Black Dog plant (Black Dog Unit 6) and a power purchase agreement for the expansion of the combined cycle Mankato Energy Center (MEC II). We call this proceeding the Competitive Acquisition Process or CAP proceeding (MPUC Docket No. E002/CN-12-1240). These resources were selected in the Minnesota CAP proceeding to meet an identified 150 to 500 MW need in the 2017 to 2019 period.

Q. ARE THE TRACK 1 AND TRACK 2 PROCESSES STILL APPLICABLE TO THE COMPANY?

A. Yes. I note, however, that our recently proposed 1,550 MW of wind additions – 600 MW of which will be based in South Dakota – has been proposed pursuant to a different acquisition process which was approved by the MPUC in our last IRP proceeding.

Q. FOR CONTEXT, WHAT IS THE RESOURCE ACQUISITION PROCESS THAT THE COMPANY UTILIZES IN NORTH DAKOTA?

A. In North Dakota, the Company committed to filing its resource plans with the North Dakota Commission so that the NDPSC and its Staff may provide input into our current plans. (NDPSC Case No. PU-07-776). We also committed to seek an advanced determination of prudence (ADP) on any new resource over 50 MW. Finally, in the settlement of our last rate case (NDPSC Case No. PU-12-813), we committed that we must obtain an ADP for any PPAs that are 50 MW or greater before we can recover the costs of the resource through our Fuel Clause Rider (FCR) mechanism.

Q. DID THE COMPANY MAKE THE FILINGS YOU JUST DESCRIBED IN THE NDPSC?

A. Yes.

Q. DID THE NDPSC GRANT THE COMPANY'S REQUESTED RELIEF REGARDING AURORA SOLAR, MARSHALL SOLAR, AND NORTH STAR SOLAR PPAS?

A. The NDPSC denied our applications for an advanced determination of prudence of the Aurora Solar project in NDPSC Case No. PU-15-095 and for the 187 MW Solar Portfolio in Case No. PU-14-810. I note that while North Dakota law makes granting an ADP binding for ratemaking purposes, the NDPSC interpretation of its statutes is that if an ADP is denied, the Company may still seek rate recovery of the costs of a particular resource in the Company's next rate case.

B. Selection of the Aurora Solar Power Purchase Agreement

Q. FOR WHAT PURPOSE WAS THE CAP PROCEEDING INITIATED IN 2012?

A. The Company's 2010 Integrated Resource Plan (IRP) identified a capacity need in the range of 150MW to 500 MW in the 2017 to 2019 time frame. The IRP proceeding completed in 2012. Shortly thereafter, the Company proposed to meet the identified capacity need by installing up to three new combustion turbines: one at it existing Black Dog Site (Black Dog Unit 6), and two at a greenfield site near Hankinson, North Dakota (Red River Valley Units 1 and 2). Because the Company was proposing self-build projects to meet the need projected in the IRP, the CAP proceeding was commenced to provide a competitive process to evaluate and select resources.

Q. IN ADDITION TO THE COMPANY'S THREE-CT PROPOSAL, WHAT OTHER PROJECTS WERE BID INTO THE CAP PROCEEDING?

A. Three independent power producers – Calpine Corporation, Invenergy Thermal Development, and Geronimo Energy – offered alternative proposals to the Company's, as did Great River Energy, an electric cooperative. Calpine's proposal was to expand its existing Mankato Energy Center from a 1x1 (a single combustion turbine paired to a single heat recovery steam generator and steam turbine) combined cycle facility to a 2x1 (two combustion turbines paired to a single heat recovery steam generator and steam turbine). Calpine projected that its proposal would add 345 MW to our system. Invenergy offered two different CT proposals – one for a 150 MW CT at its existing plant site at Cannon Falls, Minnesota, and the other for two 150 MW CTs at a new site near Hampton

Corners, Minnesota. Geronimo offered the Aurora Solar project for 100 MW that would be generated by approximately 20 distributed solar facilities located across the Company's Minnesota service territory. GRE offered a short-term capacity credit purchase of 100 to 200 MW. Except GRE, all of the resources were proposed to be added to the Company's system as Power Purchase Agreements (PPAs) to be negotiated upon selection of the project by the MPUC.

Q. DID THE COMPANY PERFORM AN ECONOMIC ANALYSIS OF THE VARIOUS OPTIONS AFTER BIDS WERE RECEIVED?

A. Yes. The Company used its Strategist resource modelling tools to perform an analysis of the bids. Because no single bid could meet the total 2017 to 2019 capacity need identified in the 2010 IRP, our analysis grouped the various bids together and analyzed the various combinations that could meet the identified need. Mr. Martin discusses our analysis in the CAP proceeding in more detail in his Direct Testimony.

Q. DID THE COMPANY MAKE ANY RECOMMENDATIONS TO THE MPUC BASED ON ITS ANALYSIS?

A. Yes. The top four portfolios had very similar results, with Black Dog 6 common to all of them. Our proposed Black Dog CT provided low-cost capacity and long-term benefits beyond those offered by the competing proposals. Also Black Dog 6 offered flexibility regarding its exact in-service date. The Company therefore recommended that Black Dog 6 be selected to meet the level of need identified by an analysis to be updated in 2014 or 2015.

After Black Dog, the Invenergy Cannon Falls Expansion and Calpine's Mankato Expansion had very similar costs in the Strategist modeling. Given that, the

Company determined that either of these projects would be cost effective resources for our customers. The Company, therefore, recommended proceeding to the contract negotiation stage with both of these proposals. During negotiations we hoped to resolve issues regarding specific terms and conditions that are typically not resolved until a bid proceeds to final contract negotiations. At the end of negotiations, we proposed that the Commission would select only one of the two projects to be awarded a contract with the Company. Because the costs of the two PPAs were likely to be similar, the Company recommended that the MPUC approve the contract that offers the most favorable terms.

In the event that both the Invenergy and Calpine projects stalled in negotiations, the Company recommended approval of our Red River Valley Unit 1.

Q. DID XCEL ENERGY RECOMMEND THE MPUC SELECT THE AURORA SOLAR PROJECT?

A. No. Our initial recommendation did not include the Aurora Solar project. Rather, our initial recommendation was predicated on our economic analysis of the various bids presented, and no portfolio of resources bid into the CAP proceeding containing the Aurora Project made the top 20 of portfolios analyzed. Mr. Martin discusses this further in his Direct Testimony.

Q. DID THE COMPANY SUPPORT THE AURORA PROJECT DURING THE CAP PROCEEDING?

A. No. Our view was that the Aurora Project was not the least-cost way for us to meet the Minnesota SES and that Black Dog 6, MEC II and the Cannon Falls expansion were all more economic alternatives to fulfill any remaining capacity need -- which, as noted, had largely disappeared by the spring of 2013.

Q. WHAT WAS THE OUTCOME OF THE CAP PROCEEDING?

A. On May 23, 2014, the MPUC issued an order in the CAP Proceeding which directing NSP to negotiate PPAs with Geronimo Energy for Aurora Solar, Calpine Corporation for MEC II, and Invenergy Thermal Development for its Cannon Falls expansion project. On February 5, 2015, the MPUC issued its final order in the CAP Proceeding confirming the selection of Aurora Solar, MEC II and Black Dog 6 to meet the identified capacity need in the 2017-2019 timeframe.

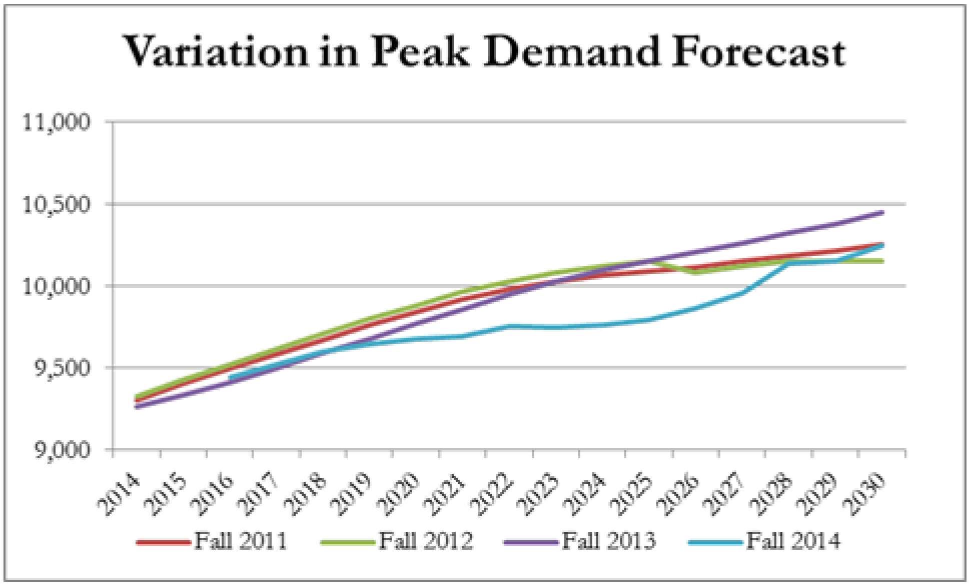
Q. DOES THE COMPANY AGREE WITH THE MPUC'S SELECTION IN CAP PROCEEDING?

A. Ultimately, yes. We did not request that the MPUC reconsider its order in the CAP Proceeding. Rather, upon reviewing the MPUC's order we recognized that it was well reasoned.

Key to the MPUC's reasoning was the interest in ensuring that there was sufficient capacity available on the NSP System during a time of forecast volatility. At the time, there was significant volatility in our load forecasts due to the impacts of the Great Recession of 2008. If load growth had bounced back to the 1 to 1.5 percent growth we had been experiencing prior to the recession, the capacity need for which the CAP Proceeding was initiated could have materialized. Figure 2 below illustrates this volatility.

Figure 2

Load Forecast Volatility



In light of the forecasting volatility and uncertainty driven by the events of 2008, we came to conclude that the conservative approach espoused by the MPUC was prudent. Consequently, we accepted the MPUC's rationale and undertook the projects selected. Importantly, we also internalized this outcome in our most recent IRP, which recently concluded. I provide the relevant MPUC CAP Proceeding Order as Exhibit___(AHC-1), Schedule 10 .

Q. IS THE AURORA SOLAR PROJECT A PRUDENT, ECONOMICAL AND EFFICIENT RESOURCE?

A. Yes. Under the circumstances at the time the resource selection was made, the Aurora Project is reasonable and necessary for the provision of service to our South Dakota customers.

First, when paired with the other resources selected by the MPUC in the CAP Proceeding–Black Dog Unit 6 and the MEC II PPA– Aurora Solar provides additional diversity of resources on our system to meet customer needs on an overall reasonable cost.

Second, because there is unavoidable uncertainty associated with forecasts, the Company determined that it was more prudent to invest in additional capacity than to risk capacity deficits and over-reliance on MISO energy markets. Moreover, Aurora Solar provides NSP with a more diverse generation portfolio and more flexibility to meet capacity needs if any of the Company's thermal resources are to be retired. Therefore, Aurora Solar also protects ratepayers against future natural gas price volatility and other generation resources that may be impacted by fluctuations in commodity prices. At the time Aurora Solar was being evaluated as a resource option, more stringent federal environmental regulation—which would have likely required the Company to retire some of its older coal fire generation resources—seemed imminent.

Third, while Aurora was being considered, the 30 percent ITC was set to be reduced to 10 percent at the end of 2016. Another of the benefits of Aurora Solar was that it could be added in time to take advantage of the ITC.

Finally, Aurora Solar provides the Company with valuable experience in managing utility scale solar with multiple interconnection points on the Company's distribution system.

C. Marshall Solar and North Star Solar

Q. HOW DID THE COMPANY SELECT THE MARSHALL SOLAR AND NORTH STAR SOLAR PROJECTS?

A. We issued an RFP on April 23, 2014 to probe the solar market for cost effective projects that could allow us to meet the newly enacted Minnesota Solar Energy Standard (SES). In response to the RFP, the Company received 111 proposals from 36 developers representing a total of 2,100 MW of solar generation. The following were the winning bids from the RFP process:

- Marshall Solar – a 62.25 MW project located near Marshall, Minnesota developed by Next Era Energy Resources, LLC;
- North Star Solar – a 100 MW project located near North Branch, Minnesota developed by Community Energies Renewables, LLC; and
- MN Solar I – a 24.75 MW project located near Tracy, Minnesota.

The three projects were selected because: (1) we needed significant solar resources for SES compliance, and (2) the pricing was attractive, since it reflected the 30 percent Federal ITC. Given that we had an opportunity to meet our entire SES obligation with resources that were capitalizing on the ITC, we selected a full portfolio which would provide enough energy for full SES compliance when coupled with the Company's solar garden program. We believe that this was the prudent action given the quick timeframes provided under Minnesota law for SES compliance, the attractive pricing and the continual uncertainty surrounding the question of ITC extension.

Q. WERE OTHER SOLAR PROJECTS UNDER CONSIDERATION AT THE SAME TIME AS THE 187 MW PORTFOLIO?

A. Yes. The CAP Proceeding was ongoing when the Company issued its RFP for

Minnesota SES compliance. We had recommended to the MPUC that only the 187 MW solar portfolio be selected – i.e., that if the MPUC selected the Aurora Solar Project, it should not select the 100 MW North Star Solar Project. However, based on our economic analysis and the fact that solar was a relatively new resource, we also recognized the value in adding 287 MW of solar to the system in the event that not all projects might proceed to commercial operation.

Q. DID XCEL ENERGY PERFORM AN ECONOMIC ANALYSIS OF THE 187 MW PORTFOLIO?

A. Yes. The 187 MW Portfolio, as a portfolio, provided net benefits of approximately $25 million system-wide when externalities were considered and net costs of approximately $14 million system-wide when externalities were not considered. Mr. Martin discusses our economic analysis in more detail in his Direct Testimony.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THIS ECONOMIC ANALYSIS?

A. The main conclusion I draw is that the Company's plan for SES compliance was generally net-neutral on a system-wide cost basis. The net benefits when considering externalities is indicative of the value of the 187 MW Portfolio at a time when the Clean Power Plan was being promulgated and there was tremendous value in obtaining attractively priced carbon free energy. The net costs when not considering externalities indicate that the pricing for the 187 MW Portfolio was as good as we had seen to date, and that the cost of SES was modest in the context of our system-wide fuel and purchased power resulting in a $14 million PVRR impact, system wide, and an approximately $25 million in cost savings on a PVSC basis.

Q. ARE THERE QUALITATIVE BENEFITS TO THE 187 MW SOLAR PORTFOLIO?

A. Yes. 187 MW Solar Portfolio increases the diversity of our resource mix by providing emission-free energy, a hedge against volatile natural gas prices and potential environmental regulation. The projects also provide accreditable capacity that will help to displace the need for future capacity resources. The 187 MW Solar Portfolio also generates Solar RECs (S-RECs) for our South Dakota customers that may be able to be monetized in the future as the S-REC market matures. These qualitative benefits partially offset the modest cost impact of this Solar Portfolio. Mr. Martin discusses these impacts in more detail in his Direct Testimony.

Q. WHAT IS THE CURRENT STATUS OF THE 187 MW PORTFOLIO?

A. The MN Solar I project (24.75 MW) faced interconnection challenges and is no longer in development. As I noted above, Marshall Solar began commercial operation in January 2017 and North Star Solar began commercial operation in December 2016

Q. DOES THE FACT THAT MN SOLAR I WILL NOT COME ONLINE IMPACT THE COMPANY'S ANALYSIS OF THE 187 MW PORTFOLIO?

A. No. Mr. Martin discusses this further.

Q. ARE NORTH STAR SOLAR AND MARSHALL SOLAR PRUDENT, ECONOMICAL, AND EFFICIENT, AND REASONABLE AND NECESSARY FOR THE COMPANY TO PROVIDE SERVICE TO ITS SOUTH DAKOTA CUSTOMERS?

A. Yes. As mentioned, North Star Solar and Marshall Solar are key resources for our compliance with Minnesota's SES. By contracting for the output of utility-scale projects that captured the pricing benefits of the ITC, the Company secured reasonably priced resources that help meet our SES obligations, modestly impact rates, and provide valuable system energy, fuel hedge value, and environmental regulation hedge value for the benefit of all our customers in all of the states we serve. Consequently, acquisition of these resources was prudent, efficient and economical

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.