Direct Testimony and Schedules
Todd Z. Simmons

Before the Minnesota Public Utilities Commission

State of Minnesota

In the Matter of the Application of Minnesota Power
For Authority to Increase Rates for Electric Utility
Service in Minnesota

Docket No. E015/GR-21-335

Exhibit ________

GENERATION OPERATIONS

November 1, 2021

TABLE OF CONTENTS

Page

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Todd Z. Simmons, and my business address is 30 West Superior Street, Duluth, Minnesota 55802.

Q. By whom are you employed and in what position?

A. I am employed by ALLETE, Inc., doing business as Minnesota Power ("Minnesota Power" or the "Company"). My current position is General Manager – Generation Operations.

Q. Please summarize your qualifications and experience.

A. I hold a Bachelor of Arts degree in Business Management from The College of St. Scholastica, in Duluth, Minnesota. Additionally, I hold a Chief "A" Engineer's License with the State of Minnesota. As a college student, I began working for Minnesota Power at the Boswell Energy Center ("BEC") as a seasonal employee in 1993 and became a full-time employee in the fuels department in 1994. From 1997 through 1999, I was a union employee in Operations for both Laskin Energy Center ("Laskin") and BEC. In January 2000, I accepted a supervisory position at BEC and worked as an Operations Superintendent. In 2005, I accepted a position with the Generation Operations group working as Production Specialist supporting all of Minnesota Power's generation facilities. I was promoted to Thermal Business Operations Manager at BEC in 2008 before I transferred to North Dakota as part of the Bison Wind Energy Center ("Bison") development as the Wind Operations Manager in 2010. I was promoted to General Manager of Wind Operations for North Dakota in 2013. I was promoted in 2017 to General Manager Renewable Operations for all Minnesota Power's renewable facilities as well as the Generation Operations engineering, generation information technology, and generation coordination departments. As the General Manager of Generation Operations, I am currently responsible for BEC, Laskin, and Rapids Energy Center in Minnesota and Bison in North Dakota. Exhibit ___ (Simmons), Direct Schedule 1 to my Direct Testimony provides my experience and qualifications.

Q. What is the purpose of your testimony?

A. The purpose of my Direct Testimony is to describe how the Company continues to transform its generation fleet while increasing renewable resources and maintaining efficient, reliable, and cost-effective services for our customers. While some of these efforts were discussed in our last rate case (Docket No. E015/GR-16-664) ("2016 Rate Case"), the Company has continued to make progress on its *Energy**Forward*** strategy. Additionally, I will give an overview of capital projects and operations and maintenance ("O&M") expenses for the Generation Operations work area included in Minnesota Power's 2022 test year and review assets placed in service since the last rate case.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following schedules to my Direct Testimony:

- MP Exhibit ___ (Simmons), Direct Schedule 1 – Statement of Qualifications; and
- MP Exhibit ___ (Simmons), Direct Schedule 2 – 2022 Test Year Capital Additions.

II. GENERATION FORWARD LOOKING FLEET

Q. What is the purpose of this section of your testimony?

A. The purpose of my Direct Testimony is to describe how the Company continues to transform its generation fleet while increasing renewable resources and maintaining efficient, reliable, and cost-effective services for our customers. While some of these efforts were discussed in our last rate case (Docket No. E015/GR-16-664), the Company has continued to make significant progress on its *Energy**Forward*** strategy. Additionally, I will give an overview of capital projects and O&M expenses for the Generation Operations work area included in Minnesota Power's 2022 test year and review various cost control measures that Generation Operations has put into place.

Q. Please describe Minnesota Power's current generation portfolio.

A. Minnesota Power's generation facilities have a net maximum capability of nearly 1,800 megawatts ("MW") and rely on a variety of fuel sources including hydro, solar, wind, coal, natural gas, and biomass to generate power. These resources, combined with a number of Power Purchase Agreements, supply energy for our approximately 145,000 residential and commercial customers, 15 municipalities, and some of the nation's largest industrial customers. Figure 1 provides a graphical representation of Minnesota Power's generating portfolio. Since 2005, the Company has reduced coal-fired generation by 600 MW through the retirement, refueling, or remissioning of seven of its nine coal fired power generators in northern Minnesota.

Figure 1. Minnesota Power's Generation Portfolio

Q. Please Describe the Focus of Minnesota Power's Generation Operations

A. Minnesota Power's Generation Operations' mission is to operate, maintain, and manage the Company's generation assets in a manner that meets customer expectations, protects both people and the environment, and provides a fair return for Company shareholders. This mission is the driving force behind maintaining the operational integrity of the Company's generation resources and is supported by a robust, comprehensive and system-wide reliability effort. Electric generating assets serve a duty cycle that reflects the inherent design and the power market demands for economic dispatch, baseload, intermediate load, and peak load. Preserving the usefulness of the assets requires capital investment and maintenance expenditures to sustain a unit's economic viability, availability, and reliability for the duty cycle it serves. Minnesota Power's generating units have traditionally served a baseload mission due to the large component of around-the-clock industrial service in the Company's customer base, as shown by the Company's load factor of nearly 80 percent, one of the highest in the nation. Over time, the Company's mission of serving its customers with large baseload generation has changed with significant additions of intermittent renewable generation already placed in service and further planned wind and solar for the future across the Midcontinent Independent System Operator ("MISO") footprint and within the Company's system. For context, Minnesota Power has added approximately 850 MW of wind power to its 1,650 MW peak demand system since 2005.

Coupling the variable nature of renewable generation with high load factors may require changes to dispatchable asset operation in order to maintain a reliable and affordable energy supply, particularly when renewable generation is high and market demands are low. The degree of impact to dispatchable resources depends upon how much renewable energy is being generated and system demand. Currently, weather impacts on renewable generation is managed by backing down the Company's dispatchable units to lower loads. However, as the renewable fleet on the system expands, there are times when dispatchable units may need to be taken off-line to make room for renewable generation. Significantly increasing the number of on/off cycles of dispatchable generating units to accommodate the availability of renewable generation will change the generation maintenance strategy due to thermal stresses, as well as the wear and tear of starting and stopping equipment. A generation plant's operating strategy requires maintenance to ensure that the generating units are available to meet customer demands and the intended mission of each unit.

The Company continues to evolve maintenance programs within good utility practices to address impacts to generating unit operation, reliability, and maintenance costs while operating in a region where the generation fleet is continuing to evolve to reduce carbon and add increasingly renewable energy sources. Minnesota Power continues to focus on reliability, while maintaining compliance with all pertinent regulations and environmental permits.

Q. How has the Company's generation supply changed since the 2016 Rate Case?

A. Table 1 provides information on the Company's current generation portfolio, including the fleet transformation that the Company has undergone since Minnesota Power filed the 2016 Rate Case.

Table 1. Minnesota Power Owned Generation

	Unit No.	Year Installed	2016 Net Capability (MW)	2021 Net Capability (MW)
Coal-fired Generation				
Boswell Energy Center in Cohasset, MN	1	1958	67	—[a]
	2	1960	67	—[a]
	3	1973	355	352
	4	1980	468[b]	468[b]
			957	820
Taconite Harbor Energy Center in Schroeder, MN	1	1957	75	75[c]
	2	1957	75	75[c]
	3	1967	--[c]	--[c]
			150	150
Total Coal-fired			1,107	970
Biomass/Coal/Natural Gas				
Hibbard Renewable Energy Center in Duluth, MN	3 & 4	1949, 1951	62	60
Laskin Energy Center in Hoyt Lakes, MN	1 & 2	1953	110[d]	98[d]
Total Biomass/Coal Natural Gas			172	158
Hydro[e]				
Group of ten stations in MN	Multiple	Multiple	120	120
Wind				
Taconite Ridge Energy Center in Mt. Iron, MN	Multiple	2008	25	25
Bison Wind Energy Center in Oliver and Morton Counties, ND	Multiple	2010-2014	497	497
Total Wind			522	522
Solar				
Camp Ripley in Little Falls, MN[f]		2017		10
HSC Solar Garden [g]		2016		0.04
Total Solar				10.04
Total Company Generation			**1,921**	**1,780.04**

(a) Boswell Energy Center Units 1 & 2 were retired on December 26 and 27, 2018, respectively.

(b) Boswell Energy Center 4 net capability shown above reflects Minnesota Power's ownership percentage of 80 percent. Wisconsin Public Power, Inc., owns 20 percent of Boswell Energy Center 4.

(c) Taconite Harbor Energy Center Unit 3 was retired in May 2015. Economic idling of Taconite Harbor Energy Center Units 1 and 2 commenced in the fall of 2016. Minnesota Power is proposing in the 2021 Integrated Resource Plan to move forward with the retirement of Taconite Harbor Energy Center units 1 and 2 in 2021.

(d) Laskin Energy Center was converted from coal to natural gas in June 2015.

(e) Hydro consists of ten stations with 34 generating units and a total nameplate capacity of 120 MW. Thomson returned to full production in the fourth quarter of 2015. Hydro stations are Prairie River, Pillager, Sylvan, Little Falls, Blanchard, Knife Falls, Scanlon, Winton, Thomson, and Fond du Lac.

(f) Camp Ripley is not currently owned by Minnesota Power, but Minnesota Power is obligated to make financing payments during the financing term, which expires in 2027. Minnesota Power currently anticipates that at the end of the financing term, the Company will exercise the option to purchase the solar array.

(g) HSC Solar Garden is a 40 kW solar array in Duluth, Minnesota and is part of the approved April 21, 2017 CSG Pilot Program.

Q. Have any Company generation resources been retired since the 2016 Rate Case?

A. Yes. BEC Unit 1 and Unit 2 ("BEC1&2") were retired in December 2018. I discuss these retirements and the resulting impacts further in my Direct Testimony.

Q. Has the Company added any generation resources since the 2016 Rate Case?

A. While we have not added any Company-owned generation resources since the Commission issued its final rate Order in our 2016 Rate Case, we have added other generation resources to our energy supply portfolio.

In 2017, 10 MW of solar generation were commissioned at Camp Ripley near Little Falls, Minnesota. This resource was brought online during the pendency of the 2016 Rate Case and was not part of that filing or this current rate case. While this resource is not currently owned by Minnesota Power, the Company is obligated to make the financing payments for the solar array and has the option to purchase the solar array at the end of the financing term. The Company is also responsible for the maintenance of the solar array and utilizes resources within the current operations staff from the Little Falls hydro facility to coordinate maintenance activities. Additionally, Minnesota Power also commissioned a Community Solar Garden in 2016. Like the 10 MW Camp Ripley Solar Project, the cost of this resource is recovered through the Company's Solar Renewable Energy Factor. Finally, we have continued supporting customer-owned installations of distributed energy resources as a part of our energy supply portfolio.

III. GENERATION BUDGETING OVERVIEW

A. Generation Capital Budgets

Q. How does Generation Operations identify its capital budget for any given year?

A. The overall capital budgeting process for any work area is explained in the Direct Testimony of Company witness Joshua G. Rostollan. Generation Operations does augment the budget development process discussed by Mr. Rostollan by including an additional level of review of the portfolio of capital projects by the Project Review Committee ("PRC"). Once approved by the PRC, it also receives management approval and is then compiled into the annual corporate capital budget presented for review and approval to the Board of Directors.

Q. Who comprises the PRC?

A. The PRC is comprised of an experienced team that includes budget analysts, reliability and facility engineers, internal technical experts, and Generation Operations leadership.

Q. What is the role of the PRC in the budget process?

A. Generation Operations' capital projects are reviewed and approved by the PRC before they are included in the Generation Operations capital budget. The PRC is a group of experienced individuals responsible for ensuring that capital projects within Generation Operations are effectively and efficiently aligned with Minnesota Power's overall business strategy, identifying and prioritizing resources, installing appropriate project management process and controls for transparency, and managing contingency and risk related to the Generation Operations work area, as a whole. Projects are presented to the PRC for additional vetting. The PRC may approve a project, send the project back for additional review or information, or deny approval of a project before the project is forwarded for management approval and included in the Company's capital budget. A complete list of the planned 2022 test year Generation Operations capital additions are included in MP Exhibit ___ (Simmons), Direct Schedule 2.

Q. Please describe Minnesota Power's recent Generation Operations capital additions.

A. The Company continues to invest capital in our generation resources to support the safe, reliable, and economic generation of electricity for our customers. While Company witness Julie I. Pierce discusses in her Direct Testimony ways in which Minnesota Power has leveraged Power Purchase Agreements to meet certain generation needs, there are Company owned generation resources that continue to provide cost-effective electricity for our customers based on our careful and thoughtful capital investments over the asset life cycle. A summary of the Company's Generation Operations actual capital additions in 2019 and 2020, 2021 projected year capital additions, and capital additions included in the 2022 test year is provided in Table 2 (Total Company) and Table 3 (MN Jurisdictional).

Table 2. Generation Operations Capital Additions (Total Company)

Total Company				
Capital Plant Additions (including Contra) -- Total Company	**2019**	**2020**	**2021**	**2022**
	Actuals	**Actuals**	**Projected Year**	**Test Year**
Steam Generation	$22.7	$3.7	$46.8	$31.2
Boswell Common	$3.1	$1.0	$15.5	$22.5
Boswell Unit 1	-	-	-	-
Boswell Unit 2	-	-	-	-
Boswell Unit 3	$15.8	$0.8	$8.6	$6.7
Boswell Unit 4	$2.4	$1.5	$22.0	$1.7
Hibbard Renewable Energy Center	$0.9	$0.3	$0.4	$0.3
Laskin Energy Center	$0.5	$0.1	$0.2	-
Taconite Harbor Energy Center	-	-	-	-
Hydro Generation	$3.5	$2.6	$3.6	$4.4
Birch Lake Reservoir	-	-	-	-
Blanchard HE Station	-	-	$0.1	$3.0
Boulder Lake Reservoir	-	-	$0.8	-
Fish Lake Reservoir	-	-	$0.1	$0.1
Fond du Lac HE Station	-	-	-	$1.2
Island Lake Reservoir	$3.3	$0.2	-	-
Knife Falls HE Station	-	-	-	-
Little Falls HE Station	-	-	$0.1	-
Pillager HE Station	-	-	-	-
Prairie River HE Station	-	-	-	-
Rice Lake Reservoir	-	-	-	-
Scanlon HE Station	$0.1	$0.2	-	-
Sylvan HE Station	-	-	-	-
Thomson HE Station	$0.1	$0.1	$0.1	-
Whiteface Reservoir	$0.1	$2.0	-	-
Winton HE Station	-	-	$2.3	-
Wind Generation	-	$2.2	$3.9	$2.8
Bison	$0.1	$0.2	$2.0	$0.1
Taconite Ridge	($0.1)	$2.0	$2.0	$2.7
Generation Other	-	-	-	-
Grand Total	**$26.2**	**$8.5**	**$54.3**	**$38.4**

Amounts in millions.
Amounts may not total due to rounding.
Amounts may include Intangible & General Plant additions.

Table 3. Generation Operations Capital Additions (MN Jurisdictional)[1]

MN Jurisdictional Amounts				
Capital Plant Additions (including Contra) -- MN Jurisdictional	2019 Actuals	2020 Actuals	2021 Projected Year	2022 Test Year
Steam Generation	$19.7	$3.2	$40.4	$27.5
Boswell Common	$2.7	$0.9	$13.4	$19.8
Boswell Unit 1	-	-	-	-
Boswell Unit 2	-	-	-	-
Boswell Unit 3	$13.7	$0.7	$7.4	$5.9
Boswell Unit 4	$2.1	$1.3	$19.0	$1.5
Hibbard Renewable Energy Center	$0.8	$0.2	$0.3	$0.3
Laskin Energy Center	$0.4	-	$0.2	-
Taconite Harbor Energy Center	-	-	-	-
Hydro Generation	$3.0	$2.2	$3.1	$3.8
Birch Lake Reservoir	-	-	-	-
Blanchard HE Station	-	-	$0.1	$2.6
Boulder Lake Reservoir	-	-	$0.7	-
Fish Lake Reservoir	-	-	$0.1	$0.1
Fond du Lac HE Station	-	-	-	$1.0
Island Lake Reservoir	$2.8	$0.2	-	-
Knife Falls HE Station	-	-	-	-
Little Falls HE Station	-	-	$0.1	-
Pillager HE Station	-	-	-	-
Prairie River HE Station	-	-	-	-
Rice Lake Reservoir	-	-	-	-
Scanlon HE Station	-	$0.2	-	-
Sylvan HE Station	-	-	-	-
Thomson HE Station	$0.1	$0.1	$0.1	-
Whiteface Reservoir	$0.1	$1.7	-	-
Winton HE Station	-	-	$2.0	-
Wind Generation	-	$1.9	$3.4	$2.5
Bison	$0.1	$0.2	$1.7	$0.1
Taconite Ridge	($0.1)	$1.7	$1.7	$2.4
Generation Other	-	-	-	-
Grand Total	**$22.7**	**$7.3**	**$46.8**	**$33.8**

Amounts in millions.
Amounts may not total due to rounding.
Amounts may include Intangible & General Plant additions.

Q. What recent capital additions have been made to the Generation Operations fleet?

A. Generation Operations' additions to plant in-service for 2019 totaled $26.2 million Total Company ($22.7 million MN Jurisdictional) and 2020 totaled $8.5 million Total Company ($7.3 million MN Jurisdictional), 2021 projected year totals $54.3 million Total Company ($46.8 million MN Jurisdictional), and 2022 budget totals $38.4 million Total Company ($33.8 million MN Jurisdictional). Table 2 provides the Total Company

[1] A summary of allocation factors used across the Company for purposes of calculating the Minnesota Jurisdictional totals is provided in Volume 3, Direct Schedules B-16 to B-19 and C-13 to C-16.

capital additions and MN Jurisdictional totals made by location. Table 3 provides the Total Company and Minnesota Jurisdictional capital additions made by location for 2022 by project title. Capital additions for the Generation fleet are evaluated to prioritize the needs of each asset to meet its intended mission and assure compliance with regulatory requirements. Projects are also reviewed to assure alignment with outage schedules and make any identified safety improvements. In addition, operational and maintenance needs are reviewed to assure the approach meets competitiveness targets for each asset and the intended mission of each site. This helps to ensure reasonable costs of the projects.

Q. Why are the capital additions for Generation Operations greater in the 2021 projected year and the 2022 test year than actual capital additions were in 2019 and 2020?

A. The capital additions shown in Table 2 and Table 3 reflect decisions the Company made in 2020 in response to operational changes necessary in light of the economic impacts of the COVID-19 pandemic. Multiple projects from 2019 and 2020 were moved into 2021 to ensure they could be completed consistent with generation needs and safety and health guidelines and mandates. Additionally, the 2022 test year includes $22.5 million Total Company ($19.8 million MN Jurisdictional) in BEC Common project additions, which are explained further in my testimony.

Q. What is driving the $54.3 million Total Company ($46.8 million MN Jurisdictional) capital additions included in the 2021 projected year?

A. In addition to certain capital investment projects shifting from 2019 and 2020 into 2021, due to the economic impacts of the COVID-19 pandemic, as I mentioned above, there are regulatory investments necessary at BEC during 2021 into 2022. The capital additions in Table 2 and Table 3 reflect investments at BEC driven by compliance with the Environmental Protection Agency's Coal Combustion Residuals ("CCR") requirements and also some projects that shifted from 2019 and 2020 aligning with an extended outage timeframe. An 11-week scheduled outage on BEC Unit 4 ("BEC4") was completed in the spring of 2021 and was shifted from 2019 and then again 2020 due to COVID-19, in which the critical path for outage was driven by the need to replace the hot reheat piping.

Q. What is driving the $38.4 million Total Company ($33.8 million MN Jurisdictional) capital additions included in the 2022 test year Budget?

A. The capital additions in 2022 test year budget reflect continued CCR projects going into service at BEC. Three specific projects driving the capital additions in 2022 are the conversion to a dry bottom ash system at the BEC facility, along with a pond dewatering system and non-CCR water management system. Additions for these three projects were $26.1 million Total Company ($23.0 million MN Jurisdictional).

Q. How does the Company manage capital projects once they are approved?

A. Following review and approval by the PRC, the project manager is responsible for the effective execution of the project. This includes building a complete scope of work, project schedule, and construction management plan. While many projects are long-planned with extended lead times, specialized equipment, and detailed outage schedules and planning, certain project schedules may be advanced or deferred when other conditions require such flexibility. Despite strong reliability, programs and condition based monitoring systems, daily operations of a 24/7 facility will experience unforeseen failures. The Company manages to its overall budget, and where an emergent issue presents itself within that year, some projects through reprioritization may need to be rescheduled or replaced with projects that address emergent work with a higher priority for employee and public safety, environmental compliance, or reliable service for our customers.

At the same time, deviations to a project with regard to any changes in cost, scope, or schedule require that the project be reviewed again by the PRC to balance the year's capital projection and competing priorities while still assuring the safe, reliable, affordable, and environmentally compliant energy our customers expect.

B. Generation Operating & Maintenance Budgets

Q. Describe Generation Operations' 2022 Operating & Maintenance budget.

A. The Generation O&M budget is based on expenses incurred while operating and maintaining the assets in our generation portfolio. Budget development at the work area level occurs through the collaboration of subject matter experts including budget analysts, maintenance leads, engineers, and the responsible budget owner. These individuals known as the work area "business team" identify and estimate prudent and practical operating and maintenance needs to support the production obligations of the units during the period of time for which the budget is being developed.

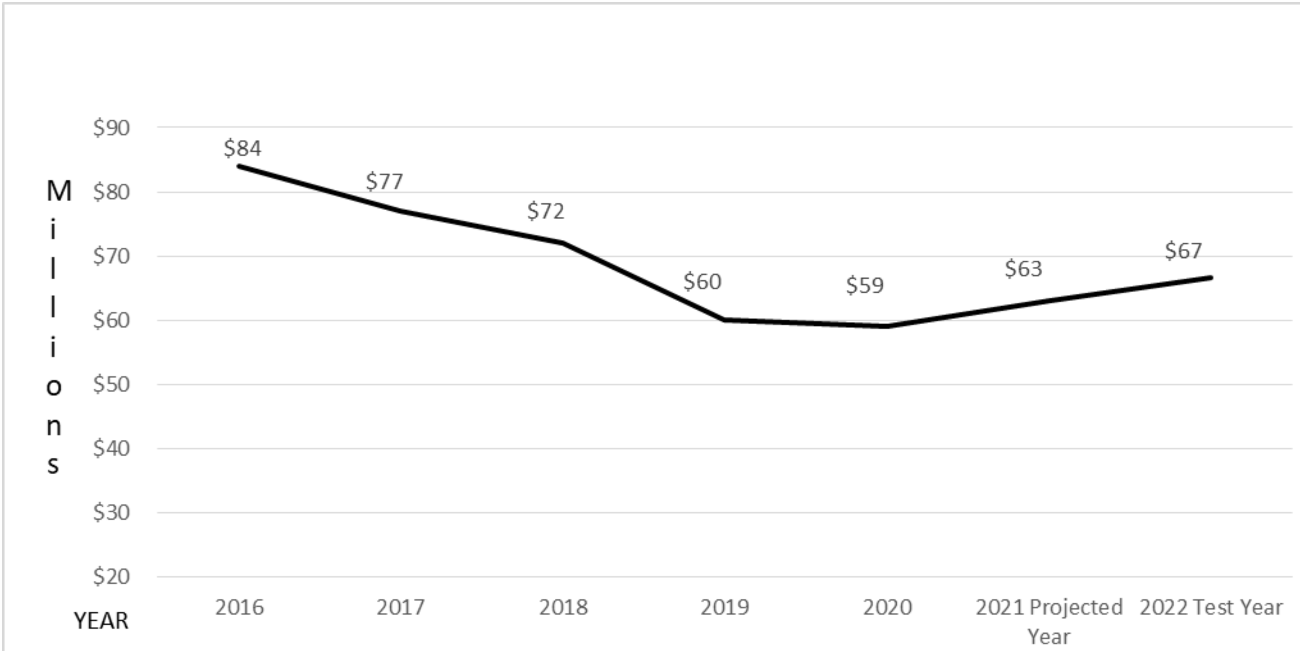
Q. What are the components of the Generation O&M budget?

A. The Generation O&M budget is comprised of expenses that are expected to occur while operating and maintaining the assets in our generation portfolio. The O&M budget is primarily comprised of the internal and contractor labor required to operate the Company's Generation facilities on a day-to-day basis, as well as expenses to perform necessary maintenance and repairs of these facilities to ensure their reliable operation. One expense included in the O&M budget, falling within the contractor labor category, is the long-term service maintenance agreement, an annual expense, at Bison. This expense is discussed further in my testimony within the Bison section. Another example of a cost driver of the O&M budget is the chemical reagents that reduce emissions at our coal-fired generation facilities. Generation Operations utilizes reagents such as ammonia, halogenated activated carbon, and lime continuously whenever these generation facilities are operating. In addition, each work area's O&M costs for purchases such as safety equipment, office supplies, and small tools and spare parts are included. These categories of costs, along with salaries, collectively represent the bulk of the Generation O&M budget and are necessary to operate the facilities to provide power generation to benefit the Company's customers.

Q. Can you illustrate the Company's Generation O&M levels since the 2016 Rate Case?

A. Yes. A summary of the Generation O&M is provided in Figure 2.

Figure 2. Generation O&M Spend (Total Company)



Q. Were there any impacts to the planned versus actual O&M expense in 2020 or 2021 based on the economic impacts of the COVID-19 global pandemic?

A. Yes, the Company did experience economic impacts to O&M expenses due to COVID-19. These impacts are summarized in Minnesota Power's COVID-19 deferred accounting quarterly report in Docket No. E,G999/M-20-427. Company witness Mr. Rostollan discusses the treatment of these costs in his Direct Testimony.

Q. Please explain the Generation Operations O&M trend over this period.

A. Figure 2 shows the trend of O&M costs in aggregate for the Generation Operations work area from the 2016 Rate Case to the 2022 test year. The graph's trend highlights Generation Operations' commitment to reviewing and keeping costs at a competitive level while transforming the generation fleet. A more detailed definition of the Company's Federal Energy Regulatory Commission ("FERC") Account cost breakdown can be reviewed in the Direct Testimony of Mr. Rostollan.

Q. What steps have led to the overall decreasing trend in O&M for the Generation Operations sites in recent years?

A. In Minnesota Power's Direct Testimony in the 2016 Rate Case, the Company highlighted a number of the practices and efforts the Generation Operations sites have deployed to contain costs as the fleet has transformed. These efforts have continued as the fleet transformation has continued, including the retirement of BEC1&2 and the subsequent rescaling of the Generation Operations support services. Some specific examples of continued cost reductions include review of staffing levels and the reduction of contractor services as our talent is redeployed and maintenance practices have evolved. Alternative contracting strategies have been reviewed and adjusted, such as the restructuring of mobile equipment maintenance contracts and reducing the scope of service to allow Minnesota Power more control over timing and scope of repairs. These alternative contracting strategies have resulted in significant cost reductions. The Company also has a shared resource philosophy where staff is cross-utilized between locations to support specialized equipment use and repairs when necessary. Figure 2 illustrates that O&M spend is basically flat, with a minor increase closely in line with the rate of inflation, across the Generation Operations work area between 2019 and the 2022 test year.

Q. How has the Company also improved its budgeting process over the past few years?

A. The Company has increased its data validation practices of reviewing expenditures by cost types and has shifted to a more rigorous FERC Account view. This FERC Account review has shifted from the historic practice of primarily focusing on work area and cost types ("responsibility centers"). Additional training has been provided to staff who are responsible for budgeting O&M costs, as well as those who are writing work orders to execute work. This training has helped align the budgeting and work execution process to more accurately reflect the FERC Accounts where costs are accumulated. In addition, open labor positions are now typically budgeted with an embedded hiring lag so as to reflect a more realistic labor outlook given reasonable attrition assumptions across a number of the generating sites, as discussed in more detail in the Direct Testimony of Company witness Laura E. Krollman.

Q. What is Generation's O&M Budget for the 2022 test year?

A. The 2022 budgeted FERC level O&M for Generation is provided in Table 4 at the Total Company level and the Minnesota Jurisdictional level.

Table 4. Generation Operations FERC Level O&M (2022 Test Year)

	Total Company	MN Jurisdictional
POWER PRODUCTION		
Steam Power Generation		
Operation	111,623,585	95,860,385
Less: Fuel Costs (Fuel Costs in FERC 50100)	(87,485,189)	(74,971,308)
Total Operation	24,138,396	20,889,077
Total Maintenance	17,969,489	15,612,198
Total Steam Power Production Expenses	42,107,885	36,501,275
Hydraulic Power Generation		
Total Operation	1,830,458	1,586,511
Total Maint	3,315,816	2,873,914
Total Hydro Power Production	5,146,274	4,460,425
Other Power Generation (wind)		
Total Operation	5,302,588	4,662,141
Total Maint	12,330,338	10,841,080
Total Other Power Production	17,632,926	15,503,221
Other Power Supply Expenses		
Purchased Power	313,101,547	270,113,018
System Control and Dispatch	654,506	575,454
Other Expenses	1,158,580	1,018,647
Less: Purchased Power (FERC 55500)	(313,101,547)	(270,113,018)
Total Other Power Supply	1,813,086	1,594,101
Total Power Production Expenses	66,700,171	58,059,022

Q. Why is the 2022 test year O&M budget approximately three percent higher than the O&M for the 2021 projected year?

A. The 2022 test year O&M budget increase from 2021 is due, in part, to the escalation factors within the contracts for Bison. In addition, the installation of a dry bottom ash system at BEC will result in some inventory becoming obsolete. The 2022 budget includes the write-off of those particular parts in accordance with Generally Accepted Accounting Principles. In recent years, these types of increases have been offset through other cost reduction efforts or through the idling, retiring, or re-missioning of the Company's baseload coal generation resources. Given the current production planning and stabilization in the fleet, such offsetting reductions cannot be maintained in perpetuity. The Company continues to scrutinize costs, and certain increases are to be expected on a go-forward basis as they relate to the escalation and inflation in Company operating costs for labor and materials. In recent years, many reductions have been offset by reductions in headcount by one-time changes in operations at baseload coal generation facilities. These facility changes cannot be counted on to continue off-setting reductions in future years.

IV. GENERATION FLEET RESOURCES

A. Boswell Energy Center

Q. What is BEC?

A. BEC, located in Cohasset, Minnesota, is Minnesota Power's largest thermal facility and only remaining source of baseload generation. BEC, at its peak, generated coal-fired power from four operating units, which were constructed over a period from 1958 to 1980. In 2016, the facility had an overall net generation capability of 957 MW. BEC1&2 were retired from operation in 2018. The two remaining operating units, BEC Unit 3 ("BEC3") and BEC4 have a combined capability of approximately 823 MW. These two units have historically provided approximately half the energy needs of Minnesota Power's customers.

BEC3 was commissioned in 1973, followed by BEC4 in 1980, to serve the region's growing natural resource industrial electric loads. The net generating capability of BEC3 is 352 MW, after turbine efficiencies were made to this asset in 2009. BEC4, which was placed into service in 1980, is Minnesota Power's largest baseload generator. Subsequent turbine efficiency investments in BEC4 during 2010 expanded the net generating capability of this unit to 585 MW. WPPI Energy (formerly Wisconsin Public

Power, Inc.) has a 20 percent (117 MW) ownership interest in BEC4. Both BEC3 and BEC4 have undergone major environmental control system retrofits, completed in 2009 and 2015, respectively. These environmental retrofits primarily targeted mercury emissions but also improved the removal of other air pollutants. The operation and maintenance strategy for BEC3 and BEC4 is aligned with a focus on reliability to ensure the units serve our customers and maintain safety and environmental compliance.

Q. What has the Commission ordered the Company to do regarding operations of BEC?

A. In the Integrated Resource Plan filed by Minnesota Power on September 1, 2015 (Docket E015/RP-15-690), the Company recommended rerouting the flue gas from BEC1&2 through the air quality control systems of BEC3 to achieve emissions reductions and continue serving the region under lower emissions targets of modified air permit conditions. Such rerouting or other emissions control for BEC1&2 was necessary due to conditions imposed under the renewed BEC air permit that was to go into effect on January 1, 2019.

Upon review of the Company's recommendation regarding BEC1&2, the Commission ordered that the Company retire BEC1&2 no later than 2022. As a result, Minnesota Power re-evaluated the investments needed to maintain compliance with the air permit conditions that would be required if operation of BEC1&2 continued beyond December 31, 2018. Given the shortened economic life, Minnesota Power decided to retire BEC1&2 just ahead of the January 1, 2019 date on which the air permit conditions took effect. In Minnesota Power's 2009 Rate Case (Docket No. E015/GR-09-1151) and in Minnesota Power's 2018 Remaining Life Depreciation Petition (Docket No. E015/D-18-544), the Commission approved an end of life for BEC1&2 of 2022. When Minnesota Power retired BEC1&2 in December 2018, a regulated asset was set up to reflect this continued recovery through 2022. The regulated asset is being amortized through 2022. Please see the Direct Testimony of Company witness Amanda L. Turner for additional information regarding the adjustment for the BEC1&2 regulated asset and accumulated amortization.

As it relates to BEC3 and BEC4, in the proceedings for the proposed *Energy**Forward*** Resource Package (Docket No. E015/AI-17-568), the Commission ordered the Company to make additional assessments of BEC3 and BEC4 in a "Baseload Retirement Study" and submit a Securitization Plan in the Company's next Integrated Resource Plan.[2] These were submitted with the Company's 2021 Integrated Resource Plan ("2021 IRP") (Docket No. E015/RP-21-33).

Q. What additional assumptions has the Company made regarding BEC in its 2021 Integrated Resource Plan filing?

A. As part of the Company's path to a sustainable carbon free future by 2050, additional bold steps will be taken at BEC 3&4 as part of its energy transition that are centered on commitments to the climate, customers, and communities. In the 2021 IRP, the Company recommended the early retirement of BEC3 by December 31, 2029 and committed to investigate options to refuel or remission BEC4 and associated reliability transmission the Company ceases coal operations by 2035.

Q. What does "retirement" of BEC1&2 mean regarding the staffing of operations at BEC?

A. With the BEC1&2 retirements in late 2018, in addition to other fleet changes that have occurred as part of the *Energy**Forward*** strategy, the BEC staff completed a workforce planning exercise to align and optimize the staffing resources needed to operate the facility and support the remaining fleet after retirement of BEC1&2. This workforce planning exercise resulted in the elimination of 57 positions and a new O&M structure at BEC. This exercise also included the rescaling of the support services group of technical and professional staff identified as Generation Operations at Minnesota Power's support services group. The BEC organizational structure is currently comprised of approximately 161 people at BEC3, BEC4, and Fuel Handling.

[2] The Commission also required development of a Securitization Plan in the 2016 Rate Case.

Q. Please describe what the Company has done with the BEC1&2 assets as part of this retirement.

A. The BEC1&2 assets remain in place, disconnected from the utility system, and have been retired in a way so as to not pose a safety or environmental risk to the BEC staff and site. The decision to retire-in-place the BEC1&2 assets was carefully planned and executed so as not to impair the operation of BEC3 and BEC4. Because BEC1&2 were the first units to be constructed and placed in service at BEC, certain total-facility infrastructure was integrated into the BEC1&2 assets. As BEC3 and BEC4 were constructed, these units were tied into some of the critical BEC1&2 infrastructure.

Portions of the BEC1&2 systems such as the water intake structure, service water pumps, electrical infrastructure, conveyors systems, and condensate water make-up systems are shared systems that are needed to support operations of BEC3 and BEC4. Prior to retirement, BEC1&2 also provided the station auxiliary steam heating needs for all of BEC. With the retirement of BEC1&2, a new auxiliary steam system was engineered and installed using steam from either BEC3 or BEC4. This new auxiliary steam system now provides BEC heating needs from either BEC3 or BEC4 during the winter months. The system was placed into service in 2018. Additional projects that had to be completed due to the retirement of BEC 1&2 included a new stack liner on the BEC3 chimney, fuel handling dust collector modifications, relocation of station air regulators, and conveyor chute section changes.

Q. Beyond the changes to the BEC facility, are there other Minnesota Power systems impacted by the retirements of BEC1&2?

A. Yes. As discussed further in the Direct Testimony of Company witness Daniel W. Gunderson, the retirement of critically-located units such as BEC1&2 necessitate Company investments in transmission infrastructure to ensure continued reliable, safe, prudent, and efficient delivery of electricity to our customers on both our transmission and distribution systems.

Q. Has there been a change in operation at BEC since the last rate review in 2016?

A. BEC3 has historically operated at a high load factor, providing dispatchable energy in the Minnesota Power system and across MISO North. The Company has been analyzing the customer, community, and operational impacts of moving BEC3 to an economic dispatch operation. BEC3 transitioned to an economic dispatch resource in July 2021 and is proposed to retire by year-end 2029 in the 2021 IRP. The current depreciable life of BEC3 extends through 2035, as summarized in Minnesota Power's 2021 Remaining Life Depreciation Petition (Docket No. E015/D-21-386) filed June 10, 2021. Minnesota Power proposes this common end of life of 2035 for all of BEC, including BEC3, as a way to recover the remaining costs without significant impacts to customers. BEC4 operates at a high load factor, providing dispatchable energy in the Minnesota Power system and MISO North. WPPI jointly owns BEC4 with Minnesota Power with a 20 percent ownership stake. In January 2021, the Company announced it will transform BEC4 to a coal-free energy supply by 2035. The current depreciable life of BEC Unit 4 also extends through 2035, as summarized in Minnesota Power's 2021 Remaining Life Depreciation Petition.

Q. Have there been any costs associated with transitioning BEC3 to economic dispatch?

A. Yes. BEC started two capital projects in 2021 to accommodate the change in mission to economic dispatch. The first project is the installation of an Economizer Bypass Duct on BEC3, which costs approximately $3.2 million Total Company ($2.8 million MN Jurisdictional) and will be in-service at the end of 2021. The new duct will bypass a portion of hot flue gas around the economizer to maintain approximately 600°F flue gas temperature at the inlet of the Selective Catalyst Reduction ("SCR"). The SCR removes NO_x from the flue gas, to meet environmental permit limits, by converting NO_x to water vapor through a chemical reaction between the NO_x, injected ammonia and catalyst plates in the SCR. This reaction requires that a specific temperature range be maintained. Under the current operation, BEC3 had to run at a minimum load of approximately 150 net megawatt-hours ("MWh") to achieve the required SCR minimum inlet temperature. By removing hot flue gas from the boiler prior to the economizer and ducting it in prior to the SCR, BEC3 will be estimated to achieve a minimum load of 75 Net MW, minimizing customer impact when the market is low.

The second project is to install natural gas heating boilers at the facility to maintain adequate temperature during cold weather months to eliminate the risk of freezing as the unit is in economic dispatch in the winter months if BEC4 becomes unavailable for generation. The heating season in Northern Minnesota runs from September through May with the critical heating months being December through February. It is estimated auxiliary heating steam is required within 72 hours after both generating boilers are offline during the critical heating months to prevent a costly plant freeze up event. The estimated cost of this project is $6.3 million Total Company and requires a three-year schedule for permitting, design, procurement, and construction. Therefore, this project is not estimated to be in-service until at least 2023. Operating a backup heat source in the form of natural gas heating boilers could potentially change the Company's fuel procurement strategy. As BEC3, and potentially BEC4, move to economic dispatch there would be an incremental cost to purchase firm natural gas transportation capacity. This would apply to both fuel for the heating boilers as well as fuel for startup of the power boilers on a more frequent basis.

Q. What are the significant capital additions at BEC since the 2016 Rate Case?

A. The investment strategy for BEC3 and BEC4 aligns with the reliability needs of our customers and current mission of the facility. BEC3 completed a scheduled turbine cycle maintenance outage in early summer 2019. Along with turbine repairs, other projects undertaken during the planned outage include environmental equipment such as a SCR layer replacement, baghouse bag replacement, and continuous emissions monitoring umbilical replacement. Additionally, burner and boiler critical replacement of parts, refurbishment of the stack liner and the addition of a stack extension, replacement of a boiler circulating water pump, replacement of the main boiler feed pump discharge elbow, pulverizer overhauls, and air heater basket replacement. In 2019 BEC3 had capital additions of $15.8 million Total Company ($13.7 MN Jurisdictional) which support the safe, reliable, and compliant operation of BEC3. These additions aligned with the ten-year turbine major maintenance cycle for an asset of this class and function.

BEC4 had a major turbine maintenance cycle outage scheduled for spring 2020. Due to the impacts of the COVID-19 pandemic, this outage was deferred to spring 2021. The safety of employees, our contracting partners, and the community were major drivers of the rescheduling of this outage. The 11-week outage included the following projects: hot reheat pipe replacement, baghouse bag replacement, burner and boiler critical replacement parts, cooling tower decking and structural members replacement, gaseous continuous emissions monitoring systems and mercury analyzer replacement, Distributed Control System ("DCS") input/output module replacement, main boiler feed pump overhaul, main boiler feed pump discharge nozzle refurbishments, pulverizer grinding section overhaul, and boiler circulating pump overhauls. In total the Company estimates capital additions in 2021 for BEC4 of approximately $22.0 million Total Company ($19.0 million MN Jurisdictional).

At BEC3, the 2021 projects include, but are not limited to, the installation of a gypsum dewatering system, economizer bypass duct, SCR catalyst layer replacement, coal piping replacement, hot reheat piping, coal feeders, feedwater heater cooler re-sleeving, DCS switch & workstation, pulverizer exhauster, boiler replacements, and stack elevator for total capital additions of $8.6 million Total Company ($7.4 million MN Jurisdictional). In 2022, BEC3 capital projects include coal piping, Flue Gas Desulfurization ("FGD") absorber pump, pulverizer exhauster, and coal feeder weigh system resulting in approximately $6.7 million Total Company ($5.9 million MN Jurisdictional) capital additions.

Over 2021-2022 BEC Common projects include hydrogen safety improvement, particulate monitoring system, titan electrodeionization, reverse osmosis membranes, dry bottom ash system, a heating boiler system, machine shop roof, simulator upgrade, the installation of the wastewater treatment system (thermal evaporator), Single Valve Gravity "B" media filter replacement, and the training center roof recoating. These projects resulted in BEC Common capital additions of $15.5 million Total Company ($13.4 million MN Jurisdictional) in 2021 and $22.5 million Total Company ($19.8 million MN Jurisdictional) in 2022.

Q. Does the 2022 budget include capital additions at BEC3?

A. Yes. BEC3 will require certain capital additions to coincide with maintenance intervals identifying overhauls or replacements needed. BEC3 has a 29-day scheduled outage in the spring of 2022. This work includes a coal pulverizer overhaul and a coal feeder control replacement as the assets have reached obsolescence and the end of their useful lives. These projects result in total capital additions of $6.7 million Total Company ($5.9 million MN Jurisdictional). These estimates are based upon the last inspection period and scope identified for upgrade or replacement. In addition to these projects mentioned, the BEC Common dry bottom ash system coinciding with CCR compliance, which is discussed further in my testimony, will be executed in 2022 and affects both BEC3 and BEC4.

Q. Does the 2022 budget include capital additions at BEC4?

A. Yes. The 2022 capital additions for BEC4 are aligned with investments aimed at supporting the designed performance of the assets, replacing worn parts, critical maintenance to maintain efficiencies and environmental compliance, and supporting continued reliability to effectively serve as a baseload resource for Minnesota Power customers and the regional grid. The planned capital investment in 2022 is aligned with a scheduled 29-day spring outage and require a longer duration outage due to the amount of time needed to tie-in the new dry bottom ash system. These investments are reasonable and prudent capital additions to maintain the useful life of this asset for the continued safe, reliable, cost-effective, and efficient generation of electricity for our customers.

Some of the planned projects for 2022 include pulverizer grinding section replacement and a feed water heater replacement. In total, $1.7 million Total Company ($1.5 million MN Jurisdictional) in capital additions is planned to be placed in-service at BEC4 in

2022. This scope of work is aligned with our ten-year capital plan and estimated life of BEC4.

Q. What is the driver behind the BEC Common investment?

A. The 2022 BEC Common capital additions of $22.5 million Total Company ($19.7 MN Jurisdictional) as shown in Table 2 are driven by CCR projects that are going into service in 2022. These projects and the CCR rule are described further in my testimony.

Q. What is the schedule for the BEC3 and BEC4 capital additions you discuss above?

A. BEC has four outages planned in 2022. Four-week outages are planned at both BEC3 and BEC4 in spring 2022 and one-week fall 2022 outages are planned at both BEC3 and BEC4.

Q. Are there any capital additions for BEC1&2 in 2022?

A. No.

Q. What are the benefits of ongoing capital investments at BEC3 and BEC4?

A. Given the current operations of these two units, ongoing maintenance is needed to ensure the safe and reliable operation of the facility for the benefit of our customers. By making continuous prudent investments, the Company maintains, and improves, the reliability of BEC3 and BEC4. As Minnesota Power's last remaining baseload generation assets, the benefits of ongoing BEC capital investments to maintain reliability for customers are even more critical.

1. Contested Case Outcomes

Q. Have operations at BEC been the subject of any additional Commission proceedings since the Company's 2016 Rate Case?

A. Yes. After the Company filed its 2020 Fuel Adjustment Clause ("FAC") compliance filing on March 2, 2020 (Docket No. E999/AA-20-171), the Department sought additional information on actual spend on O&M in the generation work area. After the Company submitted subsequent filings, the Department recommended to the

Commission that it require the Company to refund half of the unplanned outage replacement power costs that the Company incurred for the benefit of our customers from July 1, 2018 through December 31, 2019 (the FAC review period). The Department based its recommendation on the theory that a decrease in overall generation maintenance expense (across all generation resources, not just BEC) for the FAC review period, and the subsequent three outages that occurred over that same period meant that the Company was underspending on maintenance. Said another way, the Department believed that because generation maintenance expenses had decreased for the stated period of time, the Company was not performing proactive or required maintenance at the BEC facility (the only facility that experienced unplanned outages during the FAC review period) without any direct correlation to support this conclusion. The Company disagreed and provided summaries of the reasons the Department's analysis was flawed. The Commission ordered a contested case proceeding into these issues on September 16, 2020. The Administrative Law Judge provided her report to the Commission on August 11, 2021, and the matter is currently awaiting a Commission hearing.

Q. Does the Company's 2022 test year reflect any amounts directly attributable to the above-mentioned Administrative Law Judge Report?

A. Yes. In her report, the Administrative Law Judge concluded that the Company should have increased its inspection frequency and used a different inspection methodology for its high energy piping system. In reaching this conclusion, the Administrative Law Judge relied on publications from an Electric Power Research Institute Program for which Minnesota Power is not currently a member. While the report has not yet been considered by the Commission, because the Administrative Law Judge concluded that the Company's inspection schedule and investigation was not consistent with good utility practice, Minnesota Power made adjustments associated with both industry group membership and additional inspections for the BEC high energy piping systems. The adjustments are discussed in the Direct Testimony of Company witness Ms. Turner.

2. Coal Combustion Residuals

Q. What other benefits does BEC provide to customers?

A. BEC began marketing its fly ash in 2009 after the BEC3 environmental upgrades were completed. These environmental upgrades allowed for beneficial use of dry fly ash from BEC3 given the physical and marketable characteristics of the ash. Since 2013, nearly all of the fly ash generated by the BEC3 operations has been sold. Most recent revenue estimations for the 2021-2028 period include an average of $1.5 million annually. The avoided O&M costs at BEC are approximately $1.2 million for the same timeframe due to the elimination of the ash handling costs and preventing additional disposal in the ash landfill. An example of one of the benefits of the Company's efforts was the usage of BEC fly ash in the precast concrete risers installed at the Minnesota Vikings' US Bank Stadium in 2015. Other uses include several highway construction projects in northern Minnesota and in the Twin Cities metro area.

Q. Will there be any changes to the BEC fly ash sales benefit to customers in the near future?

A. Yes, starting in July 2021, revenue from the sale of fly ash could be affected by BEC3 transitioning to an economic dispatch resource and will no longer being operated on a must-run basis. Lower volumes of ash that are generated and sold could be offset by a higher contract price.

Q. Are there other potential beneficial uses for the BEC fly ash and other CCR material?

A. Yes. In addition to the BEC fly ash, Minnesota Power continues to explore other beneficial ash use markets, including BEC4 fly ash/scrubber material and BEC3 gypsum. These products have generated a small amount of revenue, have allowed Minnesota Power to explore other long-term resale options, and have offset expenses for our customers all while aligning with our environmental stewardship values.

Q. Are there other fly ash-related environmental considerations for the Company?

A. Yes. The Company continues to evaluate all coal ash impoundments/ponds that it controls under the CCR rule.

Q. What is the Coal Combustion Residual Rule?

A. The CCR Rule sets federal compliance requirements for the disposal of coal ash in ash ponds/impoundments and dry ash landfills. The CCR Rule was the Environmental Protection Agency's response to a 2008 dam failure at Tennessee Valley Authority's Kingston plant that released over one billion gallons of ash slurry. The spill devastated homes and local infrastructure and contaminated nearby waterways. Since first publication in the Federal Register (April 2015), portions of the rule have resulted in litigation and revisions, making compliance a moving target for the utility industry. Because of this changing regulatory landscape, Minnesota Power continues to explore projects and alternatives to achieve compliance and support competitive operation. This includes efforts to study the recovery and reuse of coal combustion products, as studies have indicated that ash recovery and marketing is not only the most prudent and reasonable alternative for the Company's compliance with the CCR Rule, but also minimizes impacts on the external world through beneficial reuse.

Q. What impact does the CCR Rule have on BEC's ash impoundments?

A. BEC's ash impoundments are subject to the requirements of the CCR Rule and ongoing revisions to that Rule. The ash management strategy for BEC must include a migration toward alternative technology and operation to achieve compliance. In addition, compliance deadlines are subject to change under new rulemaking and will set the stage for Minnesota Power's overall compliance strategy. The BEC ash impoundments will be required to cease receipt of CCRs and be decommissioned in accordance with the timelines specified in the Rule. Management of coal residuals at BEC are being converted from a wet handling system to a dewatering and dry management system in order to eliminate the need for the impoundments and allowing them to be decommissioned. Dry handling of CCRs will also result in less water use in plant processes and minimize the need for water treatment and discharge to surface waters. In addition, BEC has and continues to find additional water saving and reuse opportunities for all water processes (CCR and non-CCR) within the plant creating more sustainable and flexible processes.

Q. Are any of the projects Minnesota Power has identified as necessary for CCR rule compliance going into service in the 2022 test year?

A. Yes. Three projects will go into service in the 2022 test year.

Gypsum Dewatering - This BEC3 project is anticipated to go into service in the summer of 2022. This technology is a belt filter system, which dewaters the gypsum waste stream from the existing FGD system. By installing this system, it will eliminate the need for the current BEC 3 CCR Pond.

Dry Bottom Ash Systems for BEC3 and BEC4 – This BEC Common project is projected to go into service in the summer of 2022. This technology, a submerged grit conveyor, will be installed on both BEC3 and BEC4, where both units will share an ash unloading building. This installation will eliminate the need for the BEC Bottom Ash Pond.

Non-CCR wastewater management – This BEC Common project is expected to go into service at the end of 2022. It has been determined that the BEC CCR impoundments do not meet one or more of the Rule requirements and therefore must stop receiving CCRs. The BEC Bottom Ash Pond receives not only CCRs, but also multiple non-CCR wastewater streams from the plant. Since the Bottom Ash Pond has to be closed and decommissioned, an alternate means of managing non-CCR wastewater streams must be implemented. A separate project is being constructed (Dry Bottom Ash System) to manage bottom ash that is currently placed in the Bottom Ash Pond and is not included in this project and is detailed above.

B. <u>Laskin Energy Center</u>

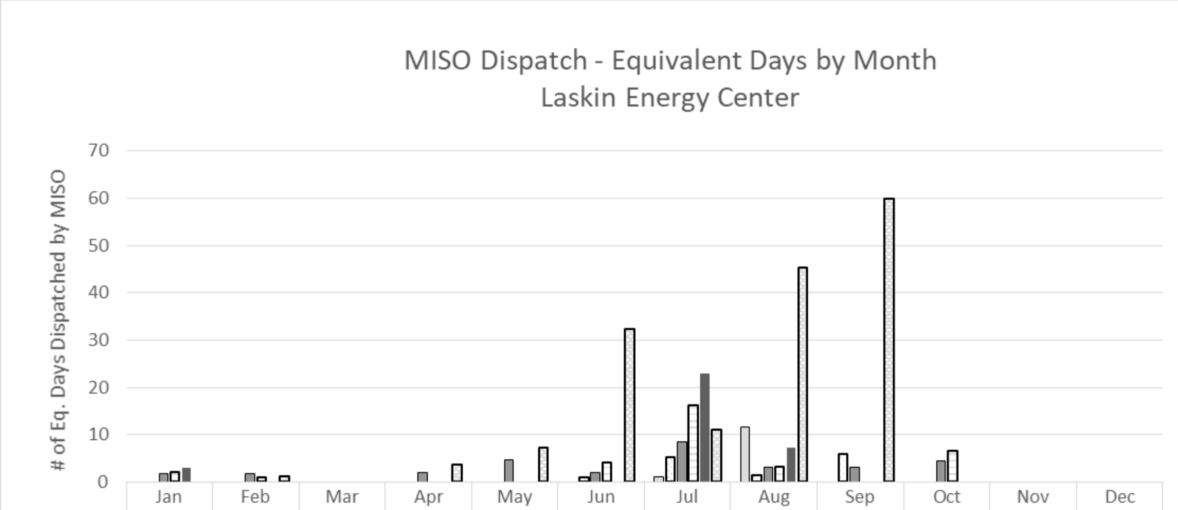
Q. Please describe Laskin.

A. Laskin is located in Hoyt Lakes, Minnesota and was commissioned in 1953 as a coal-fired facility. Laskin has two generating units, Units 1 and 2, with a capability of 98 MW that are similar in design and intended operation. To help achieve Minnesota Power's *Energy**Forward*** strategy to diversify its power supply portfolio while reducing carbon emissions, the conversion of Laskin from coal-fired to natural gas-fired generation was complete in 2015.

Q. Are there changes at Laskin because of its conversion to natural gas?

A. Yes. While the conversion to natural gas has increased the accredited capacity to 98.5 MW for planning year 2019-2020 from 69.5 MW for planning year 2015-2016 (the last year of coal operation), Minnesota Power is now operating Laskin as a peaking facility rather than a baseload resource. As a peaking facility, Laskin provides value to our customers by serving as a hedge against high regional power prices and responding to capacity needs when called upon for grid reliability. Since 2016, MISO has requested Laskin, as a peaking facility, to operate on average 2.6 equivalent days per month, as shown in Figure 3 with over 32 days between the two units in June 2021, 45 days in August, and almost 60 in September.

Figure 3. Laskin Dispatch Days*



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	0	0	0	0	0	0	1	11.6	0	0	0	0
2017	0	0	0	0	0	1	5.2	1.5	6	0	0	0
2018	1.7	1.8	0	2	4.6	2	8.5	3.2	3.1	4.4	0	0
2019	2.2	1.1	0	0	0	4.2	16.2	3.3	0	6.5	0	0
2020	2.9	0	0	0	0	0	23	7.3	0	0	0	0
2021	0	1.2	0	3.6	7.3	32.3	11	45.3	59.8			

*Dispatch information as of September 30, 2021

Q. Are there other benefits as a result of the Laskin natural gas conversion?

A. Yes. In addition to increasing capacity and diversifying the Company's energy sales, the natural gas conversion has also led to emissions reductions when compared to the coal operation of Laskin. Comparing the last three years of coal operations (2012 to 2014) to the first five years of natural gas operations (2016 to 2020), the Laskin conversion is estimated to have reduced carbon dioxide emissions by 735 pounds per MWh. In addition, sulfur dioxide, mercury, and filterable particulate matter emissions reduced by over 99 percent, while nitrogen oxide emissions were reduced by approximately 98 percent from prior coal emission levels. These emissions reductions bring significant environmental benefits to the region.

C. <u>Hibbard Renewable Energy Center</u>

Q. What is the Hibbard Renewable Energy Center ("HREC")?

A. HREC has been a part of Minnesota Power's renewable generation, regulation services, and spinning reserves for over 30 years. HREC Units 3 and 4 provide 60 MW of net capability along with dispatchable renewable energy for Minnesota Power customers. HREC is capable of burning wood, wood wastes, coal, and natural gas. HREC is a critical component as a dispatchable facility in the carbon-free strategy of Minnesota Power.

Q. What is the benefit of Minnesota Power's continued operations of HREC?

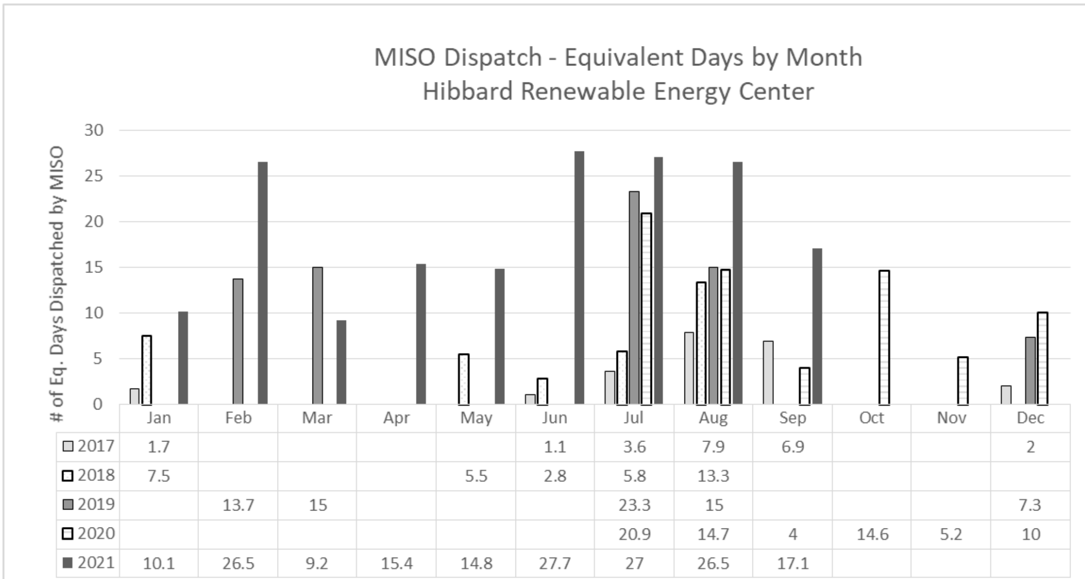
A. HREC is capable of, and originally designed for, baseload operation. It supports capacity and baseload energy generation when required. HREC's multi-fuel boilers provide steam that drives HREC's Units 3 and 4 turbine generators. Until July 2020, HREC supported papermaking processes at the adjacent Duluth paper mill.

There has been a change in the strategic operation of HREC with the Verso Duluth Mill sale and its cessation in operations. Impacts of this operational shutdown are discussed in more detail in the Direct Testimony of Company witness Frank L. Frederickson. HREC is now run when market prices and grid reliability warrant, as the baseload steam demand no longer is required to support the customer site. HREC is used as a capacity and dispatchable renewable energy resource, rather than as a baseload energy resource. As a dispatchable renewable energy resource, HREC provides a ready source of renewable energy, offering an economic cost hedge for Minnesota Power's customers as a flexible resource to support the expansion of variable renewable energy. Additionally, as a dispatchable renewable resource, HREC also provides carbon-neutral reliability services that are critical to the regional grid following the idling, re-missioning, or retiring of nine out of 11 regional coal-fired baseload generating resources. HREC continues to be offered under an economic dispatch model and is called upon to support MISO needs and Minnesota Power customer demand when needed.

Q. How often does MISO dispatch HREC?

A. HREC was called upon to support customer needs an average of 14.4 equivalent days per month (Jul 2020-Jun 2021). During peak times in February, June, July, and August, HREC operated an average of 27 equivalent-days per month across both units. As shown in Figure 4, HREC continues to be called upon to dispatch energy, demonstrating that these assets are used and very useful to provide grid reliability services.

Figure 4. HREC Dispatch Days*



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017	1.7					1.1	3.6	7.9	6.9			2
2018	7.5				5.5	2.8	5.8	13.3				
2019		13.7	15				23.3	15				7.3
2020							20.9	14.7	4	14.6	5.2	10
2021	10.1	26.5	9.2	15.4	14.8	27.7	27	26.5	17.1			

*Actual Dispatch days through September 30, 2021

D. <u>Taconite Harbor Energy Center</u>

Q. What is Taconite Harbor Energy Center ("THEC")?

A. THEC is located on the North Shore of Lake Superior near Schroeder, Minnesota. It originally included three coal-fired units, with two units installed in 1957 and one unit installed in 1967. The original output capability for Taconite Harbor was 225 MW. Minnesota Power acquired the facility in 2001 from the bankrupt LTV Steel Mining Company.

Minnesota Power ceased coal-fired generation at THEC Unit 3 in 2015, and the unit was retired-in-place. THEC Unit 1 and Unit 2 were idled in the fall of 2016. The Company sponsored a Community Advisory Panel of regional North Shore leaders from 2012 to 2016, which offered a communication platform for operating decisions. Since 2016, this group has met annually to discuss facility updates, security, and potential repurposing and redevelopment options. Repurposing ideas range from refueling the existing boilers with biomass, natural gas, or propane, or utilizing existing land and interconnect for new solar or energy storage. To date, the ideas explored have been determined unsuitable for the site and the existing infrastructure due to a variety of reasons. Some of these remissioning hurdles include no existing natural gas pipeline infrastructure, the availability of wood for biomass is limited due to being located on Lake Superior, challenging topography and geology for solar, and high costs to implement energy storage efficiently. After investigating several options for THEC, the Company determined that retirement in 2021 is the best option for customers and the site yet maintaining the depreciable life of THEC until 2026.

Minnesota Power is investigating alternative redevelopment options for the site as well as potential uses for surrounding lands, including new economic and community development that would make use of existing infrastructure. These efforts will gain additional momentum upon approval of the 2021 IRP, and we will continue to engage community leaders and the Company's economic development partners.

E. Bison Wind Energy Center

Q. What is Bison?

A. Bison, located in Oliver and Morton counties, is the largest wind farm in North Dakota at 497 MW. Bison was built in four phases over five years between 2010 and 2014, with all phases being constructed on time and below budget.

Q. How does the Company currently manage ongoing O&M at Bison?

A. Bison uses a zero-based budgeting approach to set an annual budget comprised of prudent expenses for the planned year in alignment with maintenance schedules and production estimates. Easement agreements with landowners and a long-term service agreement with the Original Equipment Manufacturer ("OEM") have escalation built into the contracts. This escalation is set by terms of these agreements, and the combined escalation in all of these contracts accounts for roughly 75 percent of the Bison O&M budget. The 2022 test year reflects this escalation.

Q. What is the source of other O&M at Bison?

A. The remaining O&M for Bison includes labor and the plant materials and services that are necessary to maintain the balance of plant as well as unit availability for the facility but are outside the scope of the long-term service agreement with the OEM.

F. <u>Taconite Ridge Energy Center</u>

Q. Please describe Taconite Ridge Energy Center ("Taconite Ridge").

A. Taconite Ridge, the first commercial wind energy center in northeastern Minnesota, began operating in June 2008. The 25 MW facility is located on property leased from U.S. Steel in Mountain Iron, Minnesota.

Q. Have there been any changes to the operations and maintenance of Taconite Ridge since the 2016 Rate Case?

A. Yes. In 2018, the federal production tax credits ("PTCs") for Taconite Ridge expired, changing the economics of the energy production from the site. Prior to the expiration of the PTCs, an internal review was performed for both operations and maintenance activities in order to evaluate options for competitiveness at the site. Maintenance activities typically completed in the short window of summer months were extended into the shoulder months to allow three technicians to perform the work previously completed by four technicians without incurring overtime. This operational change has continued since that pilot was trialed in 2018. The review of staffing and reliability practices is on-going to keep the site competitive and available for generation. The result has been reduced maintenance costs and longer run times for equipment to capture wind resource availability when most beneficial.

Q. Have there been any changes to the federal production tax credit economics at Taconite Ridge?

A. Minnesota Power continues to look for new and innovative ways to bring value to its customers. Through 2020, the Company has benefitted its customers with almost $300 million of PTCs through its Bison and Taconite Ridge wind energy facilities. In recent years, the Internal Revenue Service ("IRS") has provided guidance allowing developers to requalify existing wind projects for the production tax credit through a process known as "repowering." Beginning in 2020, the Company benefit to its customers is over $52 million in PTCs through the repowering of Taconite Ridge.

Q. What is "repowering?"

A. Repowering is achieved through replacing used equipment with new equipment while adhering to the IRS identified "80/20" requirement. To meet the requirement, the fair market value of the retained components cannot exceed 20 percent of the property's value after repower. Alternatively, the repowering costs associated with the replaced components cannot be less than 80 percent of the property's value after repower.

Q. Were there other requirements to qualify under the IRS guidelines?

A. Yes. Taxpayers must begin construction on repowering projects by December 31, 2016 to claim 100 percent of the value of the PTCs. Begin construction requirements are met by commencing physical work or incurring 5 percent of the total cost of the project.

Q. Did Taconite Ridge undertake the repowering effort?

A. Yes. Taconite Ridge met the construction requirements in 2016 through replacement or repair of pitch bearings, blades, or hubs on five of the ten turbines. Additional capital projects in 2017 through 2019 included the aforementioned replacements, as well as matrices and gearbox-bearing replacements have resulted in nine of the ten turbines having been qualified for PTCs. The final turbine qualified in August 2021.

Q. How will customers benefit from this repowering effort at Taconite Ridge?

A. The additional benefits of the PTCs resulting from repowering Taconite Ridge will be provided to customers through the Company's existing tracker mechanism within the Renewable Resources Rider ("RRR") and credited in a future cost recovery rider filing. Minnesota Power has implemented a true-up procedure to account for differences in PTCs generated by the Company's wind facilities as compared to what has been included in base rates in the 2016 Rate Case.

Q. Are there any capital additions for either Taconite Ridge or Bison in the 2022 test year?

A. Yes. The 2022 test year includes capital additions of $2.7 million Total Company ($2.4 million MN Jurisdictional) for Taconite Ridge and $0.1 million Total Company ($0.1 million MN Jurisdictional) for Bison. These costs include the anticipated replacement of generators and gearboxes that are showing signs that warrant replacement for assets to remain used and useful. This work is necessary because wind turbine components require periodic repair and replacement. This level of service is also in line with recommended operating parameters and manufacturer specifications. The 2022 test year capital additions also include a project at Taconite Ridge to address road erosion.

G. Hydroelectric Generation Facilities

Q. Please describe Minnesota Power's hydro resources.

A. Minnesota Power has used water to generate energy and serve customers since its formation more than 100 years ago. Today, the Company is the largest hydroelectric energy producer in the state, with a generating capability of approximately 120 MW. The Company's largest hydroelectric station, Thomson, has been generating renewable power for more than a century. Minnesota Power maintains the dams for the ten hydroelectric stations and six headwater storage reservoirs. The stations and reservoirs are operated under eight federal licenses issued by FERC and play a critical role in the Company's local load restoration plan and support grid reliability.

Q. What is the Thomson Restoration Project?

A. The Thomson Restoration Project was a large hydroelectric construction project to restore massive damage that occurred to the Thomson facility in June 2012 due to record rainfall and flooding. The project included the forebay canal reconstruction, electrical restoration, mechanical and general civil rehabilitation, upgrades to the water conveyance system, construction of additional spillway facilities, and refurbishment of Dam 6. The Company sought and received approval to recover costs for this project through the Company's RRR in Docket No. E-015/M-14-577. In the Company's 2016 Rate Case, all completed portions of the restoration project were moved into base rates. This included all projects except for the Thomson Spillway and Dam 6.

Q. Have the Thomson Spillway and Dam 6 Projects been completed?

A. Yes. While restoration of the generating station was complete at the time of the 2016 Rate Case, two ongoing projects associated with improving spill capacity at the Thomson Hydroelectric Facility were still in progress at that time. As spill capacity alternatives were evaluated, the Company determined that a phased approach to increasing spill capacity, as represented by these two projects, was in the best interest of our customers and communities. This approach was approved by FERC and supported by the Independent Board of Consultants.[3] The Company completed construction on the first phase of these spill capacity improvements in 2017, which increased the total spill capacity to approximately 74,000 cubic feet per second, compared to 48,000 cubic feet per second at the time of the 2012 flood. The Thomson Refurbishment of Dam 6, the last of the spillway work, was completed in 2018.

Q. Are these Thomson Spillway and Dam 6 Projects currently included in base rates?

A. No. The Thomson Spillway and Dam 6 Projects were completed after our 2016 Rate Case was filed. As a result, they are the last two Thomson projects that have been included in the Company's RRR. We are asking that these projects, along with all

[3] The Independent Board of Consultants is approved by the FERC Director to review the design, plans and specifications, and construction of the project. The Independent Board of Consultants is expected to assess the construction inspection program, construction procedures and progress, planned instrumentation, the filling procedures for the reservoir, and plans for surveillance during initial filling of the reservoir.

Thomson Restoration Project costs, be moved into base rates effective with interim rates on January 1, 2022. This request is also being made in Minnesota Power's forthcoming RRR filing expected to be submitted in late 2021. It was initially made in Minnesota Power's previous RRR filing (Docket No. E015/M-19-523), filed August 15, 2019.

Q. What was the total cost of the Thomson Restoration Project?

A. When the Company filed its original petition for the entire Thomson Restoration Project, including the Thomson Spillway and Dam 6 Projects (Docket No. E015/M-14-577), costs were estimated at $90.4 million (Total Company), net of insurance proceeds; this is the amount the Commission approved for inclusion in the RRR. The total cost of the Thomson Restoration Project was finalized at $94.3 million (Total Company), net of insurance proceeds. As part of the 2016 Rate Case, $84.5 million was approved for inclusion in base rates for the Thomson Restoration Project. Minnesota Power requests that an additional $9.8 million ($94.3 million less $84.5 million) be approved for inclusion in base rates for all the Thomson Restoration Project in this rate case. This $9.8 million includes $3.9 million that Minnesota Power reasonably and prudently incurred to complete the overall Thomson Restoration Project at the Thomson Hydroelectric Facility in excess of the early estimate of $90.4 million. The Thomson Spillway and Dam 6 Projects were completed at a final cost of $10.0 million. The difference of $0.2 million between the $10.0 million for these two projects and the $9.8 million being requested for inclusion in base rates is due to credits of $0.2 million received on the Thomson Restoration Projects, excluding the Thomson Spillway and Dam 6 Projects, since the 2016 Rate Case. This request is consistent with that of the Direct Testimony of Company witness Stewart J. Shimmin.

Q. Are there any planned capital additions at the hydroelectric stations included in the 2022 Budget?

A. Yes. The Company has identified capital additions of $4.4 million Total Company ($3.8 million MN Jurisdictional) at the hydro stations in 2022. See Table 2 and Table 3 above for a list of projects.

Q. Are there any other changes to the Company's hydroelectric stations planned for 2022?

A. No. The Company continues to evaluate our historic hydroelectric station operations. These evaluations include the potential sale or lease of land no longer necessary to comply with FERC-required hydroelectric boundary requirements. Should any such opportunities arise that require Commission approval under Minn. Stat. § 216B.50, a petition for approval would be brought to the Commission at that time.

V. CONCLUSION

Q. Does this complete your testimony?

A. Yes.

Statement of Qualifications
Todd Z. Simmons
General Manager – Generation Operations
Minnesota Power

Todd Z. Simmons is the General Manager of Generation Operations for Minnesota Power, and is responsible for portions of all fossil, gas and renewable operations and maintenance programs and staff. This responsibility includes Boswell Energy Center, Laskin Energy Center, Rapids Energy Center, and Bison Wind Energy Center in North Dakota.

Mr. Simmons earned a Bachelor of Arts Degree in Business Management from The College of St. Scholastica, in Duluth, Minnesota, and holds a Chief A Engineer's License with the State of Minnesota.

Mr. Simmons has 27 years of regulated utility experience. He joined Minnesota Power in 1994, wherein his career areas of focus have included generation facility maintenance and operations, generation operations engineering and reliability, and production planning.

Throughout his career with Minnesota Power, he has held a number of positions of increasing responsibility within the areas of operations, maintenance, engineering, project management support, and support service functions. Each new role had an increased level of diversity in operating and maintenance protocols, as well as management of employees, budgets, and facilities.

Generation Capital Additions (including Contra), 2022 Test Year

Area	Classification	Project Description	Total Company	MN Jurisdictional
Steam Generation - Boswell Unit 3	Steam Production	BEC 3 GYPSUM DEWATERING PROJECT	4,787,094	4,208,909
Steam Generation - Boswell Unit 3	Steam Production	BEC 3 COAL PIPING PROJECT	282,044	247,978
Steam Generation - Boswell Unit 3	Steam Production	BEC 3E COAL FEEDER WEIGHT SYSTEM	45,400	39,917
Steam Generation - Boswell Unit 3	Steam Production	BEC3 PULVERIZER OVERHAL - 3C exhaust	482,875	424,553
Steam Generation - Boswell Unit 3	Steam Production	BEC 3 STACK ELEVATOR REPLACEMENT	833,333	732,683
Steam Generation - Boswell Unit 3	Steam Production	U3 North MS Safety Valve Replacement	70,000	61,545
Steam Generation - Boswell Unit 3	Steam Production	3D FGD ABSORBER PUMP OVERHAUL RELIN	174,370	153,310
Steam Generation - Boswell Unit 4	Steam Production	BEC-4 LP-5 FWH Replacement	947,919	833,430
Steam Generation - Boswell Unit 4	General Plant	BEC-4 TRUCK REPLACEMENT	28,680	25,500
Steam Generation - Boswell Unit 4	Steam Production	BEC-4A Superheat Block Valve	78,527	69,042
Steam Generation - Boswell Unit 4	Steam Production	BEC-4 DCS Switch Replacement	100,354	88,233
Steam Generation - Boswell Unit 4	Steam Production	DCS Workstation Replacement	296,643	260,814
Steam Generation - Boswell Unit 4	Steam Production	Pulv. Mill Grinding Section-4A &4B	228,298	200,724
Steam Generation - Boswell Unit 4	Steam Production	Condenser Water Box West Coating	35,288	31,026
Steam Generation - Boswell Common	Steam Production	BEC DRY BOTTOM ASH SYSTEM	16,820,174	14,788,633
Steam Generation - Boswell Common	Steam Production	BEC NON-CCR WASTEWATER MANAGEMENT S	4,525,642	3,979,035
Steam Generation - Boswell Common	General Plant	BEC-F Truck Replacement	31,390	27,909
Steam Generation - Boswell Common	Steam Production	C14 Crusher House and Transfer Hous	181,010	159,148
Steam Generation - Boswell Common	Steam Production	C13 Sump Pump	120,203	105,685
Steam Generation - Boswell Common	Steam Production	BEC PARTICULATE MONITORING	44,001	38,687
Steam Generation - Boswell Common	Steam Production	BEC SIMULATOR UPGRADE	442,329	388,904
Steam Generation - Boswell Common	Steam Production	BEC TITAN EDI STACK REPLACEMENT	73,416	64,549
Steam Generation - Boswell Common	Steam Production	BEC 1&2 MACHINE SHOP WAREHOUSE ROOF	225,905	198,620
Steam Generation - Hibbard Renewable EC	Steam Production	HREC REHAB U4 GRATES	287,893	253,121
Steam Generation - Hibbard Renewable EC	General Plant	HREC ENTERPRISE ROUTER SWITCH	35,600	31,652
Steam Generation - Hibbard Renewable EC	General Plant	ANALOG PHONES GATEWAY PROJECT	25,000	22,228
Steam Generation - Laskin EC	General Plant	LEC NETWORK HARDWARE REPL	44,400	39,477
		Total Steam Generation:	**31,247,787**	**27,475,312**
Hydro Generation - Blanchard	Hydro	Blanchard Gantry Crane Improvements	2,475,620	2,176,615
Hydro Generation - Blanchard	Hydro	Blanchard PLC Migration Arc Flash	537,174	472,294
Hydro Generation - Fish Lake	General Plant	Fish Lake Security Camera	80,186	71,294
Hydro Generation - Fish Lake	Hydro	Fish Lake Stilling Well	29,301	25,110
Hydro Generation - Fond du Lac	Hydro	FDL Turbine Guide Bearing Replace	640,532	563,168
Hydro Generation - Fond du Lac	Hydro	FDL Scrollcase Liner Replace	345,006	303,337
Hydro Generation - Fond du Lac	Hydro	FDL CONCRETE BULKHEAD INTAKE BAY	126,643	111,347
Hydro Generation - Fond du Lac	General Plant	FDL CTS Project	15,000	13,337
Hydro Generation - Fond du Lac	General Plant	FDL CAMERA	30,000	26,673
Hydro Generation - Little Falls	General Plant	Little Falls CTS Project	15,000	13,337
Hydro Generation - Prairie River	General Plant	PRAIRIE RIVER CAMERA	30,000	26,673
Hydro Generation - Scanlon	General Plant	SCANLON CAMERA	30,000	26,673
Hydro Generation - Thomson	General Plant	THOMSON CTS PROJECT	15,000	13,337
		Total Hydro Generation:	**4,369,462**	**3,843,195**
Wind Generation - Bison	Wind Generation	BISON GENERATOR REPLACEMENT	125,500	110,342
Wind Generation - Taconite Ridge	Wind Generation	WEST ROAD EROSION	242,591	213,290
Wind Generation - Taconite Ridge	Wind Generation	GEARBOX CHANGE OUT (1) T3 & T6 PITC	2,247,442	1,975,996
Wind Generation - Taconite Ridge	Wind Generation	SYSTEM1 INSTALLATION	195,794	172,146
		Total Wind Generation:	**2,811,326**	**2,471,774**
		Total Generation:	**38,428,575**	**33,790,281**