Direct Testimony and Schedules
Melissa L. Schmidt

Before the Minnesota Public Utilities Commission
State of Minnesota

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

Docket No. E002/GR-19-564
Exhibit___(MLS-1)

Cost Assignment and Allocation Principles

November 1, 2019

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Melissa L. Schmidt. I am employed by Xcel Energy Services Inc. (XES), the service company subsidiary of Xcel Energy, as the Director of Corporate Accounting, which includes Corporate Accounting, Service Company Accounting, Cash Processes and Business Area Accounting.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. As Director, Corporate Accounting, I am responsible for the general administration of XES, including accounting, billing, allocations, policies and procedures, service agreements, internal audits, external audits and external reporting to state and federal regulatory agencies. Additionally, I direct Xcel Energy's Corporate Accounting group, which manages the month-end close process, legal consolidation process, maintains the general ledger, and other accounting functions and controls; the Cash Processes group, which is responsible for monitoring and reconciling the cash activity, long-term debt and other related items for all Xcel Energy affiliates and subsidiaries; and the Business Area Accounting group, which is responsible for the accounting functions for the business areas of Xcel Energy. A description of my qualifications, duties, and responsibilities is set forth in Exhibit___(MLS-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In my testimony, I:

- Present the Cost Assignment and Allocation Manual (CAAM), demonstrating how our cost assignment and allocation methodologies and processes ensure that our costs to serve customers are assigned to the appropriate entities;

- Outline the process for allocating Xcel Energy Services Company charges;
- Identify unique features of the General Allocator for the NSPM-Minnesota jurisdiction, and the adjustment necessary to implement the required allocation factor (FTE Hours rather than Number of Employees) for interim rates;
- Request that the Company be permitted to dispense with this adjustment for final rates and future cases, as it is unique to Minnesota and does not provide a consistent benefit to any jurisdiction;
- Explain the Company's process for allocating costs between its gas and electric utilities;
- Discuss affiliate transactions between the Xcel Energy operating companies; and
- Explain the process for allocating costs to our non-regulated business activities.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I present the remainder of my testimony in the following sections:

- Section II explains our cost assignment and allocation principles and processes, and shows they conform to the principles and guidance adopted by the Commission.
- Section III presents a summary of my testimony.

II. COST ASSIGNMENT AND ALLOCATION

Q. PLEASE SUMMARIZE THIS SECTION OF YOUR TESTIMONY.

A. In this section, I discuss the framework of our cost allocation and assignment principles, including the Service Agreement between XES and NSPM, and the NSPM CAAM. I then discuss the services provided by XES to NSPM, and how the cost of those services is either directly assigned (direct charge) or allocated (indirect charge) to the Company. I explain the allocation methods used, and quantify the adjustment in this case that results from the use of Total Allocated Labor Hours With Overtime (FTE Hours) in Minnesota instead of the Number of Employees in our General Allocator and certain other allocations. Finally, I discuss how we handle transactions between Xcel Energy operating company affiliates and NSPM's non-regulated business activities.

A. Cost Assignment and Allocation Framework

Q. PLEASE SUMMARIZE THE COMPANY'S OVERALL PHILOSOPHY FOR RECORDING COSTS.

A. Our overall philosophy is to record costs for all products and services in a consistent, equitable manner to ensure they are recovered from the customers of the entity responsible for the costs incurred. This philosophy is designed to reasonably apportion fully-distributed costs to individual operating companies, like NSPM, and to avoid cross-subsidization between the operating companies and any non-regulated business activities.

Q. ARE THERE GUIDING PRINCIPLES RELATED TO THIS PHILOSOPHY THAT ARE APPLIED BY XCEL ENERGY?

A. Yes. To implement this philosophy, our cost assignment and allocation process follows the guiding principles set forth in the Commission's decision in Docket No. E,G999/CI-90-1008 (Docket No. CI-90-1008). These principles are applied to both the regulated utility services and non-regulated business activities across Xcel Energy. NSPM's hierarchical cost allocation principles are as follows:

1) Tariffed rates shall be used to value tariffed services provided.
2) Costs shall be directly assigned to either regulated or non-regulated business activities whenever possible.
3) Costs that cannot be directly assigned are common costs, which shall be grouped into homogeneous cost categories. Each cost category shall be allocated based upon indirect cost causation.
4) When neither direct or indirect measures of cost causation can be found, the cost category shall be allocated based upon a general allocator.

Using this process ensures that all subsidiaries are charged for their appropriate share of costs. Thus, our efforts to appropriately allocate and assign costs are aligned with our customers' expectations and interests that they pay for only those costs that are part of the services they receive from the Company.

Q. PLEASE SUMMARIZE THE COMPANY'S APPROACH TO COST ASSIGNMENT AND ALLOCATION USING THESE PRINCIPLES.

A. In accordance with the Commission's Order in Docket No. CI-90-1008, the Company strives to direct charge wherever possible. Direct charges occur when a service being rendered is for the benefit of a specific legal entity only.

Allocated, or indirect, charges occur when services cannot be directly assigned to a specific legal entity.

Q. WHAT IS THE BASIS OF THE ALLOCATED CHARGES?

A. We use allocation percentages or ratios to assign non-Company specific costs. These allocation percentages or ratios are calculated using allocation methods and formulas based on allocation statistics reflecting Company operations, such as the number of customers, dollar amount of revenues, dollar amount of plant assets, megawatt-hours (MWh) of generation, and number of customer bills. I discuss Allocations further in Section II. C. below.

Q. HOW DOES THE COMPANY PUT THESE PRINCIPLES INTO PRACTICE?

A. We have a Service Agreement that describes the services provided to NSPM (and the other operating companies and affiliates) by XES, as well as a CAAM that identifies the methodologies used to ensure expenditures are appropriately and consistently assigned or allocated:

- among utility operations within NSPM (natural gas and electric);
- among jurisdictions within NSPM (Minnesota, North Dakota, and South Dakota); and
- to the non-regulated business activities operated within NSPM.

The CAAM also helps promote a greater understanding of the Company's cost assignment and allocation principles by providing detailed reference information for both XES and NSPM personnel.

Q. ARE THESE DOCUMENTS SUBJECT TO COMMISSION APPROVAL?

A. Yes. In its November 20, 2014 Order in Docket No. E,G002/AI-14-234

(November 2014 Order), the Commission approved the Second Amendment to the Service Agreement with certain modifications, and directed the Company to submit an annual filing for review and approval of any proposed changes to its allocation methods. We have subsequently submitted annual filings, which have been approved or acknowledged (where approval was not required) by the Commission – most recently by Commission Order dated July 10, 2019 in Docket No. E,G002/AI-19-371. A copy of the current Service Agreement between XES and NSPM is provided as Exhibit___(MLS-1), Schedule 2.

Our first CAAM was approved by the Commission as part of our natural gas rate case in Docket No. G002/GR-04-1511. NSPM's CAAM, updated effective September 30, 2019, is provided as Exhibit___(MLS-1), Schedule 3. However, the cost assignment and allocation principles applied by NSPM are not new and have been applied in the development of the test year cost of service in all of NSPM's rate cases since Docket No. G002/GR-04-1511.

Q. DOES THE CAAM REFLECT COST ALLOCATION PRINCIPLES THAT HAVE BEEN ADOPTED BY THE COMMISSION?

A. Yes. The principles reflected in the CAAM are based on the guiding principles set forth in the Commission's Order in Docket No. CI-90-1008. In our June 1, 2015 Petition seeking approval of the most recent amendments to the Service Agreement, the Company re-affirmed its commitment to the cost allocation principles established in Docket No. CI-90-1008, and described how its cost allocation procedures implement and adhere to those principles.

Q. WHAT WAS THE PURPOSE AND FUNCTION OF THE MOST RECENT UPDATES TO THE CAAM?

A. The CAAM is updated annually as well on an ad-hoc basis to ensure that the included documentation and methodologies listed within the CAAM remain current. There have been several updates to the CAAM since the last rate case filing. The changes primarily relate to updates of active legal entities in the Xcel Energy holding company structure and terminology changes related to the transition from the JD Edwards General Ledger to the new SAP system.

Q. HOW WAS THE CAAM USED IN THIS PROCEEDING?

A. The 2020 budgeted costs used by Company witness Mr. Benjamin Halama to develop the 2020 test year revenue requirement were developed using the principles contained in the current CAAM. Because the Company does not forecast future allocation factors, those same principles in the current CAAM were likewise utilized to develop 2021 and 2022 plan year revenue requirements.

Q. HAS THE COMPANY PROVIDED A LIST OF, AND DESCRIPTIONS FOR, THE VARIOUS ALLOCATION METHODS USED FOR THE TEST YEAR?

A. Yes. A list of the allocation factors used by XES in its general ledger system for each of our operating companies is provided in Exhibit___(MLS-1), Schedule 4. This schedule also includes a description of each method, by Allocating Cost Center (ACC), as well as the 2020 test year percentage allocated to NSPM. Exhibit___(MLS-1), Schedule 5 presents a detailed description of the statistics used to calculate the allocation percentages for these methods, as well as the calculation of the NSPM allocation percentages by ACC. The detailed descriptions of the calculation of the allocation ratios can be found in Appendix A of the Service Agreement, included as Schedule 2.

Q. ARE THESE THE SAME ALLOCATION METHODS THAT ARE APPLIED IN OTHER JURISDICTIONS SERVED BY XCEL ENERGY UTILITY OPERATING COMPANIES?

A. Yes, with one exception. These allocation methods are the same allocation methods that are in effect and approved in NSPM's other operating jurisdictions (North Dakota and South Dakota), and in the operating jurisdictions of the other Xcel Energy operating companies: Northern States Power Company – Wisconsin (NSPW), Public Service Company of Colorado (PSCo) and Southwestern Public Service Company (SPS). However, a change to the General Allocator used for the Minnesota jurisdiction of NSPM was required by the Commission's March 15, 2011 Order in Docket No. E,G002/AI-10-690. I discuss the impact of using the General Allocator specific to Minnesota in Section II.C.1. below.

Q. HAVE THERE BEEN ANY CHANGES TO THE COMPANY'S ACCOUNTING AND ALLOCATION SYSTEMS SINCE THE COMPANY'S LAST RATE CASE?

A. Yes. The Company implemented its new SAP General Ledger in January of 2016, and the Work and Asset Management system in phases in 2016 and 2017. Because it has been several years since these systems were implemented, by the time of this rate case filing the Company has made a number of other filings with the Commission using SAP.

There were no changes in either the legal entities or functional organizations as part of the implementation of the SAP General Ledger, nor any changes to the calculation of allocation statistics. However, as with any new system, the terminology and process steps may differ somewhat from one system to another. Company witness Mr. Gregory Robinson provides additional updates on the SAP General Ledger in his Direct Testimony.

Q. IS THE COST ASSIGNMENT AND ALLOCATION FRAMEWORK SUBJECT TO OVERSIGHT BY ANY OTHER REGULATORY AGENCIES?

A. Yes. The cost assignment and allocation framework utilized by XES is under the oversight of the Federal Energy Regulatory Commission (FERC) through periodic audits.

Q. HAS XES GONE THROUGH AN AUDIT BY THE FERC IN WHICH THE COST ASSIGNMENT AND ALLOCATION FRAMEWORK WAS REVIEWED?

A. Yes. XES underwent a FERC audit that covered the period of January 1, 2014 through December 31, 2017. The final audit report was issued on August 29, 2019, as FERC Docket No. FA17-4-000.

Q. WHAT WERE THE FINDINGS AS A RESULT OF THE FERC AUDIT THAT HAVE AN IMPACT ON THE TEST YEAR?

A. The FERC audit of XES identified two audit findings that may have an impact on the 2020 test year. The first finding related to the allocation of capital software to Xcel Energy's non-utility entities. The Company is currently evaluating the impacts of this finding, but expects any impact to the test year to be immaterial. The second finding related to the cost allocation of XES income tax expense. The Company is currently evaluating the impacts of this finding but also expects any impact to the test year to be immaterial. There were no other findings identified in the FERC audit report that impact the test year.

B. Xcel Energy Services Company Charges

Q. PLEASE DESCRIBE THE SERVICES PROVIDED BY XES.

A. Consistent with the CAAM and the Service Agreement, XES cost assignment and allocation processes apportion costs including:

- Operations and maintenance (O&M) costs of providing corporate services to XES affiliates, such as NSPM. These services typically include any managerial, financial, legal, engineering, marketing, auditing, statistical, advertising, publicity, tax, research or any other service, information or data, which is sold or furnished for a charge;
- O&M costs for preliminary planning related to capital software projects that benefit more than one operating company or other affiliate;
- Shared facilities O&M costs that are recorded in cost pools referred to in SAP as Allocating Cost Centers (ACCs). These costs may include (depending on the shared facility), administrative property services labor and non-labor costs, utility expenses, maintenance costs for structures and systems, a pro-rated share of property taxes (for owned buildings), and rent and occupancy expenses (for leased buildings); and
- Fleet, Warehousing, and Purchasing O&M costs that are recorded to ACCs.

Q. PLEASE PROVIDE AN OVERVIEW OF THE METHODS XES USES TO ASSIGN AND ALLOCATE COSTS TO THE COMPANY.

A. XES direct *assigns* costs when the specific operating company or affiliate (or the specific department or business area within the operating company or affiliate) that should be billed can be identified. For example, the XES Controller's organization can charge NSPM for the work that has been performed to prepare a regulatory filing in Minnesota. Another example is an

XES engineer direct charging labor costs related to a gas distribution project directly to the Gas Distribution business area under the Minnesota Gas jurisdiction. Direct charge internal orders are used to track and directly charge a specific affiliate as well as a specific jurisdiction and/or business area within that affiliate.

XES *allocates* costs when a service provided by XES employees cannot be directly assigned to one affiliate. A description of the XES allocation methodology for each service is provided in the Allocation Ratios section of Appendix A of the Service Agreement. To allocate costs that cannot be directly assigned, XES first identifies homogeneous cost pools known as ACC's that have the same cost driver and then selects the allocation method that has the most cost-causative relationship to the cost driver to allocate the charges within the ACC. Indirect charge internal orders are used to track and assign costs that cannot be directly assigned to the appropriate ACC. For example, the Risk Management department negotiates the corporate umbrella insurance policies that benefit every operating affiliate. Therefore, the costs incurred by Risk Management to negotiate the policies would be considered indirect charges and allocated proportionally to every operating affiliate.

Q. WHAT DOES XES DO TO ENSURE THAT XES COSTS ARE RECORDED, ASSIGNED, AND ALLOCATED CORRECTLY?

A. XES takes the following steps to ensure its costs are correctly recorded, assigned, and allocated:

- Makes the policies and procedures regarding the recording of costs available on the Xcel Energy internal web site for access by all Xcel Energy personnel;

- provides mandatory training, delivered through a combination of classroom, online/computer-based and individual/one-on-one trainings;
- conducts regular reviews of any allocations by Finance and Accounting department personnel; and
- conducts internal audits of XES policies and procedures and their application.

The Company also monitors the accuracy of XES charges through formal and informal review processes, including business area reviews with the operating company Presidents.

Q. DOES XES REPORT ITS CHARGES TO THE XCEL ENERGY OPERATING COMPANIES AND AFFILIATES?

A. Yes. XES files a Federal Energy Regulatory Commission (FERC) Form 60 report on an annual basis. This report shows XES billings to the Xcel Energy operating companies and affiliates, including a list of approved allocation methods. A copy of the 2018 XES FERC Form 60 is provided as Exhibit___(MLS-1), Schedule 6.

Q. CAN XCEL ENERGY OPERATING COMPANIES CHARGE COSTS TO XES?

A. No. The operating companies can only direct charge costs to other operating companies or affiliates.

C. Allocation Methods and Factors

Q. IN GENERAL, WHAT ARE THE ALLOCATION METHODS USED TO ASSIGN COSTS TO AND WITHIN THE COMPANY?

A. There are two allocation methods: the General Allocator and Utility Allocations. I will discuss each of these allocation methods in this section of my testimony.

Q. WHAT IS THE BASIS OF THESE ALLOCATION METHODS?

A. Each allocation method relies on underlying entity statistics relevant to the types of charges that need to be allocated to an Xcel Energy operating company, affiliate, or business area within an operating company. In this way, the Company seeks to align its cost allocation methods with a reasonable representation of cost causation.

Q. HOW OFTEN ARE THE OPERATING COMPANY AND AFFILIATE STATISTICS USED IN THE XES ALLOCATION FACTORS UPDATED?

A. The XES allocation ratios and allocation factors are recalculated annually effective for April business based on the prior calendar year statistics.[1] XES will also update the statistics used in the allocation ratios and allocation factors when there is a significant change, such as the addition or deletion of an operating company or affiliate, if material.

Q. ARE THE ALLOCATION METHODS CONSISTENT ACROSS ALL XCEL ENERGY OPERATING COMPANIES?

A. No. As I mentioned previously, in Docket No. E,G002/AI-10-690, the Commission required that NSPM use a unique allocation method for its General Allocator in order to develop just and reasonable rates. Specifically, we use FTE Hours instead of Number of Employees in allocating costs to the

[1] XES annually updates four allocation statistics and allocation percentages related to the Joint Operating Agreement and trading activities starting with January business. The statistics are based on the prior calendar year.

Minnesota jurisdiction. A list of the allocation factors for XES based on FTE Hours is provided in Exhibit___(MLS-1), Schedule 4(a). As I describe in more detail below, the Company is proposing to discontinue this cumbersome adjustment, unique to NSPM, for purposes of final rates in this proceeding and for future filings.

Q. HAVE THERE BEEN ANY CHANGES IN THE COMPANY'S USE OF ALLOCATIONS SINCE THE COMPANY'S LAST RATE CASE?

A. Yes. The Company previously utilized an "Allocating Workorders" method, by which the Company used specific workorders to assign certain types of Business Systems-related costs to various functional areas in the operating companies under the prior JDE General Ledger. With the switch to the SAP General Ledger and as individual projects wrapped or moved to direct charging, allocating workorders are no longer utilized.

Q. WHAT DEGREE OF PRECISION DOES THE COMPANY ACHIEVE FOR ITS ALLOCATORS?

A. The Company has incorporated the use of four decimal places in the development of the relevant allocators since the Commission's order in Docket No. E,G002/AI-10-690. We have likewise calculated the allocators in this case using four decimal places.

1. *General Allocator*

Q. PLEASE DESCRIBE THE GENERAL ALLOCATOR.

A. The General Allocator is used to allocate common costs to operating companies or affiliates. The calculation used in all jurisdictions other than Minnesota is comprised of three equally-weighted factors: assets, revenues, and number of employees. However, in Minnesota this allocator currently uses FTE Hours instead of Number of Employees.

Q. WHY IS FTE HOURS USED IN PLACE OF NUMBER OF EMPLOYEES IN MINNESOTA?

A. In a March 2011 Order in Docket No. E,G002/AI-10-690,[2] the Commission required the Company to use the FTE Hours in place of Number of Employees, finding that the former allocation method resulted in a more accurate, just, and reasonable allocation of labor costs. Since that time, in each rate case the Company has made an adjustment to its allocation methods to reflect the FTE Hours allocation method rather than Number of Employees.

Q. PLEASE DISCUSS THE FTE HOURS COMPONENT OF THE GENERAL ALLOCATOR IN MORE DETAIL.

A. The FTE Hours component of the three-factor formula that makes up the General Allocator is calculated as a percentage of the total direct and allocated labor hours for NSPM relative to the total direct and allocated labor hours for all the affiliates receiving allocations through the General Allocator. It is averaged together with total assets and total revenues, the other two allocation factors that make-up the General Allocator. In contrast, all other Xcel Energy operating companies use Number of Employees, rather than FTE Hours, as part of the three-factor formula that makes up the General Allocator.

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[2] *In the Matter of Northern States Power Company's Cost Allocation Procedures and General Allocator,* Docket No. E,G002/AI-10-690, ORDER REQUIRING CHANGE IN GENERAL ALLOCATOR AND REQUIRING FILINGS (March 15, 2011); ERRATUM NOTICE (March 25, 2011).

Q. Is the General Allocator the only allocation method in which Number of Employees was replaced with FTE Hours to allocate costs to the Minnesota jurisdiction?

A. No. FTE Hours is also included in other allocation methods besides the General Allocator, as noted in Exhibit___(MLS-1), Schedule 5(a). The greatest impact is, however, to the General Allocator.

Q. If allocations to the Minnesota jurisdiction are different than for other operating companies and NSPM jurisdictions, does the Company have to manually calculate the adjustment necessary for this case?

A. Yes. Our systems only allow us to use a single allocation calculation for each allocation method. Because Minnesota is the exception, our systems are set up to allocate costs using Number of Employees rather than FTE Hours. Therefore, it is necessary that we manually make an adjustment to the costs allocated to the State of Minnesota for purposes of this rate case.

Q. What is the Company proposing in this proceeding?

A. For final rates in this proceeding, the Company is proposing to discontinue using a unique component in the General Allocator for the FTE Hours just for the Minnesota operating company. As I discuss in more detail below, the requirement to use a different allocator in Minnesota makes our allocations inconsistent across jurisdictions and does not provide a consistent benefit or greater accuracy than allocations based on number of employees. All other jurisdictions we serve use allocations based on number of employees for purposes of setting rates.

Q. HAS THE COMMISSION DISCUSSED THE USE OF THE FTE HOURS COMPONENT OF THE GENERAL ALLOCATOR IN ANY ORDERS SINCE THE COMPANY'S LAST RATE CASE?

A. Yes. In particular, in Docket No. E002/AI-17-577, the Commission approved the Administrative Services Agreement between XES and Nicollet Projects I, LLC "with the understanding that any difference between the employee ratio and allocated labor hours with overtime allocation methods will be adjusted in future rate-recovery proceedings, in which Xcel will have the burden to show that all cost allocations are consistent with past Commission orders."[3] The Commission did not, however, as part of that order, evaluate the underlying assumptions or mechanics related to the use of this unique component of the Company's General Allocator for Minnesota. Rather, the Commission's Order refers to the Department's comments regarding the continuing applicability of the March 2011 Order.

Q. WHY IS THE COMPANY PROPOSING TO DISCONTINUE THIS COMPONENT IN THE GENERAL ALLOCATOR?

A. Because Minnesota is alone among the jurisdictions Xcel Energy serves in requiring use of FTE Hours rather than Number of Employees, a unique adjustment must be developed each time the Company makes a filing using the General Allocator. Further, the use of FTE Hours sometimes reduces and sometimes increases the allocations to the Minnesota operating company, depending on the circumstances at the time of calculation. Finally, the Number of Employees allocation is accepted as a reasonable allocation basis

[3] *In the Matter of Xcel Energy's Petition for Approval of Affiliated Interest Agreements*, Docket No. E002/AI-17-577, ORDER APPROVING AFFILIATED INTEREST AGREEMENTS at 7 (June 12, 2018).

in the other jurisdictions we serve, and discontinuing the calculation would make all jurisdictions consistent while reducing the use of resources for this one allocation method.

Q. DID THE COMPANY NONETHELESS CALCULATE THE FTE HOURS ADJUSTMENT FOR PURPOSES OF THIS CASE?

A. Yes. Consistent with the Commission's prior orders, including Order Point 3 in the Commission's June 12, 2018 Order in Docket No. E002/AI-17-577,[4] for interim rates the Company utilized the FTE Hours adjustment in light of the existing Commission Order. This adjustment is discussed in the Company's Interim Rate Petition and supporting schedules. Additionally, the Company is providing the allocation percentages resulting in that adjustment in my Direct Testimony and Exhibit___(MLS-1), Schedules 5(a) and 5(b).

Schedule 5(a) shows the number of direct and allocated labor hours used to calculate the allocation ratios for the 2020 test year.

Schedule 5(b) shows the calculation of the adjustments to the 2020 test year (for NSPM Total Company), applying the difference between the Number of Employees factor and the FTE Hours factor included in Minnesota's General Allocator, as well as the other affected ACC allocators.

Q. PLEASE COMPARE THE FTE HOURS ADJUSTMENT FOR THE 2016 TEST YEAR IN THE COMPANY'S LAST RATE CASE AND THE 2020 TEST YEAR IN THIS CASE.

A. In our last rate case, the FTE Hours adjustment for the 2016 test year was a reduction of $1,474,671 to the cost of service for the Minnesota Electric

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[4] *"The ASA between XES and Nicollet Projects will be subject to future review in rate recovery proceedings where Xcel will demonstrate that all cost allocations are consistent with past Commission orders."*

jurisdiction. The 2020 test year FTE Hours adjustment would be a reduction to the cost of service of $3,334,664 for the Minnesota Electric Jurisdiction, while the 2021 FTE Hours adjustment would be a reduction of $3,368,505. The derivation of these FTE Hours adjustments are set forth in Mr. Halama's Volume 4, Test Year Workpapers, Interim Adjustment ADJ 7.

Q. WHY IS THE FTE HOURS ADJUSTMENT FOR THE 2020 TEST YEAR GREATER THAN THE ADJUSTMENT IN THE 2016 TEST YEAR?

A. As an indicator of business activity, the calculation of FTE Hours reflects higher or lower levels of labor hours worked to support operational needs. The change in the FTE Hours adjustment from the 2016 test year to the 2020 test year results substantially from the fact that the number of NSPM employees decreased from 2014 (the last full year prior to our 2015 rate case filing with a 2016 test year) to 2018 (the last full year prior to this rate case filing) at a higher rate than the other operating companies, as well as Xcel Energy as a whole, with increased headcount on XES. The increased headcount on XES is primarily due to transfers of employees from the operating companies to facilitate operating company-specific employees working across entities as demand necessitates. This change results in a greater deviation between the FTE Hours allocation percentage and the Number of Employees allocation percentage for this case, and thus a larger adjustment in the 2020 test year compared to 2016. Table 1 below provides a comparative summary of the direct FTE Hours calculation by business area as well as indirect FTE Hours from XES for the 2016 and 2020 test years.

Table 1

FTE Hours by Business Area for the 2016 and 2020 Test Years

(Based on 2014 and 2018 Actual NSPM Total Company Results)

	2016 Test Year (2014 Actuals)		**2020 Test Year** (2018 Actuals)		
	Overtime Hours	**Regular Hours**	**Overtime Hours**	**Regular Hours**	**Net Change in Hours**
Business Area					
Chief Executive Officer	-	124	-	-	**(124)**
Corporate Services	3	26,886	1	14,655	**(12,233)**
Distribution Operations	289,138	1,966,747	374,417	1,951,183	**69,715**
Energy Supply	316,953	1,813,137	282,454	1,569,759	**(277,878)**
Financial Operations	102	101,174	90	110,228	**9,042**
Gas Systems	16,807	238,053	24,843	253,431	**23,414**
General Counsel	86	38,801	133	32,885	**(5,870)**
Nuclear Generation	394,692	2,731,238	187,033	2,083,177	**(855,719)**
Transmission	199,087	949,437	158,839	818,897	**(170,789)**
Utilities & Operations Services	40,863	1,099,850	33,346	1,148,447	**41,080**
Direct Hours	**1,257,731**	**8,965,447**	**1,061,156**	**7,982,**662	**(1,179,361)**
Indirect Hours	**21,933**	**882,348**	**21,202**	**833,736**	**(49,342)**
Total Hours *	**1,279,664**	**9,847,795**	**1,082,358**	**8,816,398**	**(1,228,703)**

* Amounts may not total due to rounding.

Table 1 shows primary decreases in labor hours in the Nuclear Generation, Energy Supply, and Utilities & Corporate Services business areas, and a primary increase in Operations Services. The various reasons behind these business area changes in hours are discussed in the Direct Testimony of Company witnesses Mr. Randy A. Capra and Mr. Timothy J. O'Connor.

As shown in Table 1, there is an overall decrease in total FTE hours in the 2020 test year compared to 2016.

Q. HOW DOES THE DECREASE IN TOTAL FTE HOURS IN 2020 COMPARED TO 2016 RESULT IN A GREATER REDUCTION TO THE COST OF SERVICE FOR THE 2020 TEST YEAR COMPARED TO 2016?

A. To understand how this *decrease* in total FTE hours is consistent with a greater FTE hours *reduction* to the cost of service, it is necessary to consider how the FTE hours allocation percentage has changed as compared to the Number of Employees allocation percentage. Table 2 provides a comparative summary of the allocation percentages for the 2016 and 2020 test years.

Table 2

Allocation Percentage Comparison for the 2016 and 2020 Test Years

(Based on 2014 and 2018 Actual Hours and Headcount)

	2016 Test Year (2014 Actuals)			**2020 Test Year** (2018 Actuals)		
	NSPM	**All OpCos**	**NSPM Percentage**	**NSPM**	**All OpCos**	**NSPM Percentage**
FTE Labor Hours	11,127,459	22,940,934	48.5048%	9,898,756	21,707,649	45.6003%
Number of Employees	4,661	9,259	50.3402%	3,875	7,937	48.8220%
Variance			**(1.8354%)**			**(3.2217%)**

The greater deviation between the Number of Employees and FTE Hours allocation percentages in the 2020 test year compared to the 2016 test year is largely due to a greater reduction in the number of NSPM employees compared to the other operating companies. Specifically, the total number of operating company employees decreased by 1,322 with NSPM employees decreasing by 786, representing 59 percent of the total decrease.

As a result, the difference between the two allocation method percentages increased by 1.3863 percent from the 2016 test year to the 2020 test year. This increase is responsible for approximately $1.1 million of the increase in the FTE Hours adjustment to the 2020 test year compared to the 2016 test year.

Q. DO YOU EXPECT CHANGES IN FTE HOURS IN THE FUTURE?

A. Yes. If the FTE Hours adjustment were to continue to be utilized, we continue to expect changes in FTE Hours each year based on operational needs and specific events in a given year. Overtime hours can change significantly from year to year based on the timing of major overhauls and/or outages at the generating plants, as well as overtime related to major storm events. While the number of employees is also subject to change, the Company already develops its General Allocator on the basis of this factor (along with total assets and total revenues) for its other jurisdictions. Therefore, it would be much more straightforward and more consistent to utilize the same calculations across all jurisdictions.

2. Utility Allocations

Q. WHAT IS THE PURPOSE OF COMMON UTILITY ALLOCATIONS?

A. Utility O&M allocations are developed to allocate NSPM common (electric and natural gas) utility Administrative and General (A&G) costs charged to FERC accounts 920 through 935 to the electric and natural gas utilities. They are also used to allocate NSPM common (electric and natural gas) utility customer accounting, customer information, and sales costs charged to FERC accounts 901 through 917 to the electric and natural gas utilities.

Q. WHAT METHOD IS USED TO ALLOCATE NSPM'S COMMON CUSTOMER-RELATED UTILITY COSTS BETWEEN THE ELECTRIC AND NATURAL GAS UTILITIES?

A. The method used to allocate common customer-related utility costs between electric and natural gas utilities is the number of customer bills. The method used to allocate the commodity portion of the bad debt between electric and natural gas utilities is associated revenues.

Q. IS THE METHOD USED TO ALLOCATE NSPM'S COMMON A&G-RELATED UTILITY COSTS BETWEEN THE ELECTRIC AND NATURAL GAS UTILITIES THE SAME AS WAS USED IN NSPM'S LAST ELECTRIC AND GAS RATE CASES?

A. Yes. In the 2020 budget, A&G-related FERC accounts 925 and 926 were allocated to the electric and natural gas utilities based on labor. However, all other common A&G costs were allocated to the electric and natural gas utilities based on a weighted three-factor formula comprised of revenue, utility plant-in-service, and supervised O&M. (Supervised O&M refers to operations and maintenance costs which are included in FERC account 500 through FERC account 917). The three-factor formula measures three distinct aspects of the Company's operations and results in an appropriate assignment of costs to the electric and natural gas utilities. This is consistent with NSPM's hierarchical cost allocation principles described earlier in my testimony. Step 4 of these principles specifically addresses the use of the General Allocator when no cost causative link exists.

Q. HAVE THE 2020 TEST YEAR O&M AND RATE BASE UTILITY ALLOCATION METHODOLOGIES AND ALLOCATION FACTORS BEEN PROVIDED IN YOUR TESTIMONY?

A. Yes. The 2020 test year O&M Utility Allocation methodology is explained in Section VI of the CAAM, provided as Schedule 3, and the 2020 test year Utility Allocation factors are further detailed in Exhibit___(MLS-1), Schedule 7. The 2020 test year utility rate base allocation methodology is explained in

Section VI of the CAAM, and the 2020 test year utility rate base allocation factors are detailed in Mr. Halama's Direct Testimony.

D. Affiliate Transactions

Q. PLEASE EXPLAIN THE BENEFITS THAT SHARED O&M SERVICES BETWEEN NSPM AND THE AFFILIATED UTILITY OPERATING COMPANIES PROVIDE TO MINNESOTA ELECTRIC CUSTOMERS.

A. The provision of services by NSPM to other legal entities reduces overhead costs related to those services, which further reduces the amount of cost recovered from our customers. In addition, NSPM receives services from other operating companies at cost, which eliminates the need for NSPM itself to develop those services and incur the related overhead costs.

Q. WHAT TYPES OF O&M CHARGES BETWEEN NSPM AND OTHER AFFILIATED UTILITY OPERATING COMPANIES ARE INCLUDED IN THE 2020 TEST YEAR BUDGET?

A. The allocated O&M charges between NSPM and other Xcel Energy regulated operating companies in the 2020 test year are limited to small amounts of facilities costs and related labor overhead, which are discussed in Section V of the CAAM. Exhibit___(MLS-1), Schedule 8 provides a description and the dollar amounts of the charges between NSPM and NSPW, PSCo, and SPS. For the 2020 test year, estimated charges from NSPM to NSPW total $0.02 million, and charges from NSPW to NSPM total $0.03 million. All test year charges between NSPM and either SPS and PSCo total only $0.01 million, as illustrated in Schedule 8.

Q. ARE THERE ANY OTHER AFFILIATED INTEREST TRANSACTIONS YOU WISH TO NOTE?

A. Yes. The Company recently noted that with the Commission's decision in Docket Nos. E002/PA-18-702 and E002/GS-15-620, the Company has formed a new subsidiary through which it will purchase the Mankato Energy Center entities as a non-rate-regulated investment under the same power purchase agreement that currently exists with Southern Power Company and has filed the affiliated interest petition with the Commission in Docket No. E002/AI-19-622. Because the core terms of the Company's PPA are not expected to change, we do not anticipate material changes to amounts allocated to the Minnesota Electric jurisdiction for the 2020 test year. However, we will provide any updates that may be needed during the course of the proceeding.

E. Non-Regulated Business Activity Allocations

Q. PLEASE IDENTIFY NSPM'S NON-REGULATED BUSINESS ACTIVITIES.

A. The Company's non-regulated business activities include the following, which are further described in Section III of NSPM's CAAM:

- HomeSmart (in-home appliance protection services);
- ConnectSmart (mover connection services);
- Customer Owned Street Lighting Maintenance (maintenance services to communities for street light systems);
- Sherco Steam Sales to Liberty Paper Inc. (steam supplied to meet thermal needs); and
- InfoWise GX Meter (an energy management tool to help businesses manage energy usage).

Q. WHAT IS THE AMOUNT OF NSPM'S NON-REGULATED BUSINESS ACTIVITIES?

A. NSPM's non-regulated business activities account for approximately 0.60 percent of NSPM's total 2018 actual revenues and 0.12 percent of NSPM's 2018 actual operating expenses (excluding purchased fuel, power and gas expenses). Exhibit___(MLS-1), Schedule 9 provides the supporting calculations. The 2018 Securities and Exchange Commission (SEC) Form 10-K for NSPM, provided as Exhibit___(MLS-1), Schedule 10, is the source of the statistics used in these calculations, and the applicable pages are referenced in the footnotes of Schedule 9.

Q. ARE ALLOCATIONS MADE TO NSPM'S NON-REGULATED BUSINESS ACTIVITY ALLOCATIONS?

A. Yes. Non-regulated business activity allocations ensure that: 1) the costs for services provided to NSPM's non-regulated business activities are billed representing a fully-distributed cost; and 2) gas and electric utility operations are not subsidizing non-regulated business activities. In addition, NSPM allocates a portion of its corporation costs using the labor-related overhead and the corporate residual allocation presented in Exhibit___(MLS-1), Schedule 11. All payments made to or by NSPM as a result of these activities related to affiliated interest agreements are reasonable and have not resulted in any customer subsidization of non-regulated activities of affiliated companies.

Q. HAVE THE TEST YEAR NON-REGULATED BUSINESS ACTIVITY ALLOCATION METHODOLOGY AND ALLOCATION FACTORS BEEN PROVIDED IN YOUR TESTIMONY?

A. Yes. The test year allocation methodology is explained in Section VII of the

CAAM, and the test year non-regulated business activity allocation factors are listed in Schedule 11.

Q. ARE THERE ANY ADDITIONAL COMMISSION ORDERS REGARDING ALLOCATIONS THAT YOU HAVE NOT ADDRESSED IN YOUR DIRECT TESTIMONY?

A. Yes. In the Commission's August 3, 2015, Order in Docket No. E002/AI-14-759, the Commission required that the Company provide certain information related to Xcel Energy Transmission Development Company, LLC, or Xcel Energy Southwest Transmission Company, LLC. The Company acknowledges the reporting requirements under that Commission Order, but it has nothing to report at this time as the transmission companies have not undertaken any relevant projects. Consequently, we ask to be released from any further reporting requirements related to these affiliated interests unless or until any such work is undertaken by Xcel Energy Transmission Development Company, LLC, or Xcel Energy Southwest Transmission Company, LLC.

III. SUMMARY AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR TESTIMONY

A. Our cost allocation processes are designed to ensure that the costs to provide service to our customers are recorded to the appropriate legal entities. They emphasize the importance of accuracy, facilitate business area accountability, and result in a reasonable, accurate forecast of the costs we expect to incur.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Melissa L. Schmidt

Director of Corporate Accounting
Xcel Energy Services Inc.

I received a Bachelor of Arts in Business Administration, with a major in accounting, from the University of St. Thomas in 2000.

My current position with XES is Director, Corporate Accounting which includes Corporate Accounting, Service Company Accounting, Cash Processes and Business Area Accounting. I am responsible for the general administration of XES, including accounting, billing, allocations, policies and procedures, service agreements, internal audits, external audits and external reporting to state and federal regulatory agencies. Additionally, I direct: Xcel Energy's Corporate Accounting group, which manages the month-end close process, legal consolidation process, maintains the general ledger, and other accounting functions and controls; the Cash Processes group, which is responsible for monitoring and reconciling the cash activity, long-term debt and other related items for all Xcel Energy affiliates and subsidiaries; and the Business Area Accounting group, which is responsible for the accounting functions for the business areas of Xcel Energy which includes Energy Supply, Transmission, Distribution, Gas Engineering & Operations and Corporate Services.

I have been employed by XES since April 2005, holding positions in Corporate Accounting, Internal Reporting, Benefits Accounting, SOX management office and External Reporting.

Prior to joining XES, I was employed by Temple Inland as a senior financial and operational auditor. Prior to Temple Inland, I was employed by Andersen LLP and Deloitte LLP where I performed financial statement audits for companies in various industries including energy and utilities, manufacturing, retail and travel services.

FOURTH AMENDMENT TO SERVICE AGREEMENT
BETWEEN
NORTHERN STATES POWER COMPANY,
a Minnesota corporation
AND
XCEL ENERGY SERVICES INC.

THIS FOURTH AMENDMENT TO SERVICE AGREEMENT ("Fourth Amendment") is made and entered into as of the 14th day of December 2015, by and between Northern States Power Company, a Minnesota corporation ("Client Company") and Xcel Energy Services Inc. ("Service Company").

WHEREAS, Client Company and Service Company entered into that certain Service Agreement dated as of August 15, 2004 ("Original Service Agreement");

WHEREAS, the Original Service Agreement has been amended from time to time;

WHEREAS, the Original Service Agreement was most recently amended by a Third Amendment to Service Agreement dated as of May 28, 2015 and filed with the Minnesota Public Utilities Commission in Docket No. E,G002/AI-15-536 ("Third Amendment" and the Original Service Agreement as amended, the "Amended Service Agreement");

WHEREAS the Amended Service Agreement is subject to the jurisdiction of state utility commissions and the Federal Energy Regulatory Commission;

WHEREAS, additional amendments to the Amended Service Agreement are necessary to recognize new allocation methodologies that are being implemented by the Client Company and Service Company, consistent with the Minnesota Public Utilities Commission's final order in Docket No. E,G002/AI-15-536, dated November 19, 2015;

WHEREAS, Client Company and Service Company mutually desire, by means of this Fourth Amendment, to further amend the Amended Service Agreement as set forth below;

NOW THEREFORE, for and in consideration of the mutual covenants contained in this Fourth Amendment and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the par-ties agree as follows:

1. Appendix A to the Amended Service Agreement is deleted in its entirety and replaced with the contents of Schedule 1 to this Fourth Amendment.

2. Except as expressly amended by this Fourth Amendment, all other provisions of the Amended Service Agreement remain in full force and effect.

3. This Fourth Amendment to Service Agreement shall be subject to all necessary and prudent regulatory approvals.

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF, the parties hereto have executed this Fourth Amendment to Service Agreement to be executed as of the date and year first above written.

XCEL ENERGY SERVICES INC.

BY: ______________________________
Name: Judy M. Poferl
Title: Senior Vice President, Corporate Secretary and Executive Services

NORTHERN STATES POWER COMPANY,
A MINNESOTA CORPORATION

BY: ______________________________
Name: Christopher B. Clark
Title: President

[SIGNATURE PAGE TO FOURTH AMENDMENT TO SERVICE AGREEMENT]

SERVICE AGREEMENT

This Service Agreement is made and entered into this 15th day of March, 2007, by and between Northern States Power Company (Minnesota) ("Client Company") on behalf of itself and all of its subsidiaries, and Xcel Energy Services Inc. ("Service Company").

WITNESSETH

WHEREAS, Service Company is a subsidiary of Xcel Energy Inc. ("Xcel Energy"), a public utility holding company under the Public Utility Holding Company Act of 2005, that has been formed to provide support services for Xcel Energy and its subsidiaries in a manner consistent with applicable regulatory requirements; and

WHEREAS, Client Company is a utility operating company subsidiary of Xcel Energy and an affiliate of Service Company; and

WHEREAS, Service Company and Client Company have entered into this Service Agreement whereby Service Company agrees to provide and Client Company agrees to accept and pay for various services as provided on a cost basis, that requires the Service Company to fairly and equitably allocate costs among all associate companies to which it renders services, including the Client company.

NOW THEREFORE, in consideration of the premises and the mutual agreements herein contained, the parties to this Service Agreement covenant and agree as follows:

ARTICLE I - SERVICES

Section 1.1 Service Company shall furnish to Client Company, as requested by Client Company, upon the terms and conditions hereinafter set forth, such of the services described in Appendix A hereto, at such times, for such periods and in such manner as Client Company may from time to time request and that Service Company concludes it is able to perform. Service Company shall also provide Client Company with such special services, in addition to those services described in Appendix A hereto, as may be requested by Client Company and that Service Company concludes it is able to perform. In supplying such services, Service Company may arrange, where it deems appropriate, for the services of such experts, consultants, advisers, and other persons with necessary qualifications as are required for or pertinent to the provision of such services.

Section 1.2 Client Company shall take from Service Company such of the services described in Section 1.1, and such additional general or special services, whether or not now contemplated, as are requested from time to time by Client Company and that Service Company concludes it is able to perform.

Section 1.3 The services described herein or contemplated to be performed hereunder shall be directly assigned or allocated by activity, project, program, work order or other appropriate basis. Client Company shall have the right from time to time to amend, alter or rescind any activity, project, program or work order provided that (i) any such amendment or alteration that results in a material change in the scope of the services to be performed or equipment to be provided is agreed to by Service Company, (ii) the cost for the services covered by the activity, project, program or work order shall include any expense incurred by Service Company as a direct result of such amendment, alteration or rescission of the activity, project, program or work order, and (iii) no amendment, alteration or rescission of an activity, project, program or work order shall release Client Company from liability for all costs already incurred by or contracted for by Service Company pursuant to the activity, project, program or work order, regardless of whether the services associated with such costs have been completed.

Section 1.4 Service Company shall use its best efforts to maintain a staff trained and experienced in the design, construction, operation, maintenance, management and general administration of public utility properties.

ARTICLE II - COMPENSATION

Section 2.1 As compensation for the services to be rendered hereunder, Client Company shall pay to Service Company all costs which reasonably can be identified and related to particular services performed by Service Company for or on its behalf. The methods for assigning or allocating Service Company costs to Client Company, as well as to other associate companies, are set forth in Appendix A.

Section 2.2 Service Company shall periodically review the methods of assignment or allocation of costs described in Appendix A. Such methods of assignment or allocation of costs may be modified or changed by Service Company subject to providing Client Company three months advance notice; and will be subject to state regulatory approval and Federal Energy Regulatory Commission (FERC) jurisdiction.

Section 2.3 No change in the organization of Service Company, the type and character of the companies to be serviced, the methods of assigning or allocating costs to associate companies, or in the scope or character of the services to be rendered shall be made unless such change is consistent with any applicable regulatory requirements.

Section 2.4 Service Company shall render a monthly statement to Client Company that shall reflect the billing information necessary to identify the costs charged for that month. By the nineteenth (19th) day of each month, Client Company shall remit to Service Company all charges billed to it by the 23rd of that same month.

Section 2.5 In the event of a dispute between the Operating Company and/or affiliate and an XES service provider regarding a billing methodology and/or amount, representatives from the parties involved along with XES Service Company Accounting will meet to discuss the issues. If a resolution cannot be reached, the issue will be referred to each party's executive management for final resolution. The Minnesota Public Utilities Commission retains jurisdiction to review any decision made under this section that affects Minnesota ratepayers.

Section 2.6 It is the intent of this Service Agreement that the payment for services rendered by Service Company to Client Company under this Service Agreement shall cover all the costs of its doing business (less the costs of services provided to affiliated companies not a party to this Service Agreement and to other non-affiliated companies, and credits for any miscellaneous items), including, but not limited to, salaries and wages, office supplies and expenses, outside services employed, property insurance, injuries and damages, employee pensions and benefits, miscellaneous general expenses, rents, maintenance of structures and equipment, depreciation and amortization, and compensation for use of capital.

ARTICLE III - TERM

Section 3.1 This Service Agreement shall become effective upon its execution and shall continue in full force and effect until terminated by Service Company or Client Company, upon not less than one year's prior written notice to the other party. This Service Agreement shall also be subject to termination or modification at any time, without notice, if and to the extent performance under this Service Agreement may conflict with any regulatory requirement of the FERC or state commission applicable to either Service Company or Client Company adopted before or after the effective date of this Service Agreement.

ARTICLE IV - LIMITATION OF LIABILITY AND INDEMNIFICATION

Section 4.1 In performing the services hereunder, Service Company will exercise due care to assure that the services are performed in an appropriate manner, meet the standards and specifications set forth in any applicable request for service and comply with the applicable standards of law and regulation. However, failure to meet these obligations shall in no event subject Service Company to any claims by or liabilities to Client Company other than to reperform the services and be reimbursed at cost for such reperformance. Service Company makes no other warranty with respect to its performance of the services, and Client Company agrees to accept such services without further warranty of any nature.

Section 4.2 To the fullest extent allowed by law, Client Company shall and does hereby indemnify and agree to save harmless and defend Service Company, its agents and employees from liabilities, taxes, losses, obligations, claims, damages, penalties, causes of action, suits, costs and expenses or judgments of any nature, on account of, or resulting from the performance and prosecution of any services performed on behalf of Client Company pursuant to this Agreement, whether or not the same results or allegedly results from the claimed or actual negligence or breach of warranty of , or willful conduct by, Service Company or any of its employees, agents, clients, or contractors or its or their subcontractors or any combination thereof.

ARTICLE V - MISCELLANEOUS

Section 5.1 All accounts and records of Service Company shall be kept in accordance with either the General Rules and Regulations promulgated by the FERC pursuant to the PUHCA 2005,in particular, the Uniform System of Accounts for Subsidiary Service Companies or the Uniform System of Accounts Prescribed for Public Utilities and Licensees subject to the Provisions of the Federal Power Act promulgated by the FERC, as each is in effect from and after the date hereof.

Section 5.2 New direct or indirect subsidiaries of Xcel Energy, which may come into existence after the effective date of this Service Agreement, may become additional client companies of Service Company and subject to a service agreement with Service Company, or an existing client company may wish to obtain additional services from Service Company. Likewise, an existing direct or indirect subsidiary of Xcel Energy may cease to be a client company or cease to take individual services from Service Company. In either event, the parties hereto shall make such changes in the scope and character of the services to be rendered and the method of assigning or allocating costs of such services as specified in Appendix A, subject to the requirements of Section 2.3, as may become necessary to achieve a fair and equitable assignment or allocation of Service Company costs among all associate companies.

Section 5.3 In the event a Client Company changes the scope of services that it takes from Service Company (pursuant to Section 1.3) or terminates this Service Agreement (pursuant to Section 2.1), the Service Company may bill such Client Company a charge that reflects a proportionate share of any significant residual fixed costs (i.e., incurred costs or commitments to incur costs) that were incurred or committed to incur in contemplation of providing such Client Company service prior to the notice of termination. Examples of fixed costs include, but are not limited to, costs to upgrade computer hardware and software systems to meet Client Company's specifications.

Section 5.4 Service Company shall permit Client Company access to its accounts and records, including the basis and computation of allocations.

Section 5.5 This Service Agreement supercedes the Service Agreement executed as of August 15, 2004.

IN WITNESS WHEREOF, the parties hereto have caused this Service Agreement to be executed as of the date and year first above written.

XCEL ENERGY SERVICES INC.

BY:________________________________
Name: Cathy J. Hart
Title: Vice President and Secretary

NORTHERN STATES POWER COMPANY
(MINNESOTA)

BY:_______________________________
Name: David M. Sparby
Title: Executive Vice President, Acting President and CEO

Appendix A

DESCRIPTION OF SERVICES TO BE PROVIDED BY XCEL ENERGY SERVICES INC. AND DETERMINATION OF CHARGES FOR SUCH SERVICES TO THE OPERATING COMPANIES AND OTHER AFFILIATES

Description of Services Provided

A description of the services provided by Xcel Energy Services is detailed below. Identifiable costs will be directly assigned to the Operating Companies and other affiliates. For costs that are for services of a general nature and cannot be directly assigned, the method of allocation is described below for each service provided.

a) *Executive Management Services**

Description - Represents charges for Xcel executive management and services, including, but not limited to, officers of Xcel.

Method of Allocation - Executive Management indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.

b) *Investor Relations**

Description - Provides communications to investors and the financial community. Coordinates the transfer agent and shareholder record keeping functions and plans the annual shareholder meeting.

Method of Allocation - Investor Relations indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.

c) *Internal Audit**

Description - Reviews internal controls and procedures to ensure assets are safeguarded and transactions are properly authorized and recorded. Evaluates contract risks.

Method of Allocation - Internal Audit indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.

d) *Legal**

Description - Provides legal services related to labor and employment law, litigation, contracts, rates and regulation, environmental matters, real estate and other legal matters.

Method of Allocation - Legal indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.

*e) Claims Services**

Description - Provides claims services related to casualty, public and company claims.

Method of Allocation - Claims Services costs will be direct charged. Any costs that cannot be direct charged will be allocated using the General Allocator.

*f) Corporate Communications**

Description - Provides corporate communications, speech writing and coordinates media services. Provides advertising and branding development for the companies within the Xcel system. Manages and tracks all contributions made on behalf of the Xcel system.

Method of Allocation - Corporate Communications indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.

*g) Employee Communications**

Description - Develops and distributes communications to employees.

Method of Allocation - Employee Communications indirect costs will be allocated based on the Employee Ratio.

*h) Corporate Strategy & Business Development**

Description - Facilitates development of corporate strategy and prepares strategic plans, monitors corporate performance and evaluates business opportunities. Develops and facilitates process improvements.

Method of Allocation - Corporate Strategy & Business Development indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.

*i) Government Affairs **

Description - Monitors, reviews and researches government legislation.

Method of Allocation - Government Affairs indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.

*j) Facilities & Real Estate**

Description - Operates and maintains office buildings and service centers. Procures real estate and administers real estate leases. Administers contracts to provide security, housekeeping and maintenance services for such facilities. Procures office furniture and equipment.

Method of Allocation - Facilities & Real Estate indirect costs will be allocated to the Operating Companies based on the Employee Ratio.

*k) Facilities Administrative Services**

Description - Includes but is not limited to the functions of Mail Delivery, Duplicating and Records Management.

Method of Allocation - Facilities Administrative Services indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio

*l) Supply Chain**

Description - Includes contract negotiations, development and management of supplier relationships and acquisition of goods and services. Also includes inventory planning and forecasting, ordering, accounting and database management. Warehousing services includes receiving, storing, issuing, shipping, returns, and distribution of material and parts.

Method of Allocation - Supply Chain will be direct charged. Any management and oversight of the payment and reporting services activities that cannot be direct charged will be allocated using the Invoice Transaction Ratio.

*m) Supply Chain Special Programs**

Description - Develops and implements special programs utilized across the company such as procurement cards, travel services, and compliance with corporate MWBE (minority women business expenditures) program goals.

Method of Allocation - Supply Chain Special Programs indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.

*n) Human Resources**

Description - Establishes and administers policies related to employment, compensation and benefits. Maintains HR computer system, the tuition reimbursement plan, and diversity program. Coordinates the bargaining strategy and labor agreements with union employees. Provides technical and professional development training and general HR support services.

Method of Allocation - Human Resources indirect costs will be allocated based on the Employee Ratio.

*o) Finance & Treasury**

Description - Coordinates activities related to securities issuance, including maintaining relationships with financial institutions, cash management, investing activities and monitoring the capital markets. Performs financial and economic analysis.

Method of Allocation - All Finance & Treasury indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio, except for:

(1) all indirect costs associated with proprietary trading activities, which will be allocated based on the Joint Operating Agreement Peak Hour Megawatt Load Ratio, provided, however, that indirect costs provided jointly for both generation trading activities and proprietary trading activities will be allocated based on the Joint Operating Agreement Labor Hours Ratio.

*p) Accounting, Financial Reporting & Taxes**

Description - Maintains the books and records. Prepares financial and statistical reports, tax filings and ensures compliance with the applicable laws and regulations. Maintains the accounting systems. Coordinates the budgeting process.

Method of Allocation – All Accounting, Financial Reporting & Taxes indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio, except for:

(1) indirect costs incurred for services associated with proprietary trading activities, which will be allocated based on the Joint Operating Agreement Peak Hour Megawatt Load Ratio, provided, however, that indirect costs provided jointly for both generation trading activities and proprietary trading activities will be allocated based on the Joint Operating Agreement Labor Hours Ratio.

*q) Payment & Reporting**

Description - Processes payments to vendors and prepares statistical reports.

Method of Allocation - Payment & Reporting indirect costs will be allocated to the Operating Companies based on the Invoice Transaction Ratio.

*r) Receipts Processing**

Description - Processes payments received from customers of the Operating Companies and affiliates.

Method of Allocation - Receipts Processing indirect costs will be allocated based on the Customer Bills Ratio.

*s) Payroll**

Description - Processes payroll including but not limited to time reporting, calculation of salaries and wages, payroll tax reporting and compliance reports.

Method of Allocation - Payroll indirect costs will be allocated based on the Employee Ratio.

*t) Rates & Regulation**

Description - Determines the Operating Companies' regulatory strategy, revenue requirements and rates for electric and gas customers. Coordinates the regulatory compliance requirements and maintains relationships with the regulatory bodies.

Method of Allocation - Rates & Regulation indirect costs will be allocated to the Operating Companies based on the Direct Labor Ratio.

*u) Energy Supply Engineering and Environmental**

Description - Provides engineering services to the generation business. Establishes policies and procedures for compliance with environmental laws and regulations. Researches emerging environmental issues and monitors compliance with environmental requirements. Oversees environmental cleanup projects.

Method of Allocation - Energy Supply Engineering and Environmental services will be direct charged, and administrative support functions that cannot be direct charged will be allocated using the Total Plant Ratio.

*v) Energy Supply Business Resources**

Description - Provides performance, specialists and analytical services to the Operating Companies' generation facilities.

Method of Allocation - Energy Supply Business Resources indirect costs will be allocated using the MWh Generation Ratio.

*w) Energy Markets Regulated Trading & Marketing**

Description - Provides electric trading services to the Operating Companies' electric generation systems including load management, system optimization and resource acquisition.

Method of Allocation - Energy Markets Regulated Trading & Marketing indirect costs will be allocated to the Operating Companies based on the Total MWh Sales Ratio, except for:

(1) indirect costs incurred for services associated with proprietary trading activities, which will be allocated based on the Joint Operating Agreement Peak Hour Megawatt Load Ratio, provided, however, that indirect costs provided jointly for both generation trading activities and proprietary trading activities will be allocated based on the Joint Operating Agreement Labor Hours Ratio.

*x) Energy Markets - Fuel Procurement**

Description - Purchases fuel for Operating Companies electric generation systems (excluding nuclear).

Method of Allocation - Energy Markets Fuel Procurement indirect costs will be allocated based on the MWh Generation Ratio.

*y) Energy Delivery Marketing**

Description - Develops new business opportunities and markets the products and services for the Delivery Business Unit.

Method of Allocation - Energy Delivery Marketing will be direct charged.

*z) Energy Delivery Construction, Operations & Maintenance (COM)**

Description - Constructs, maintains and operates electric and gas delivery systems.

Method of Allocation - Energy Delivery COM indirect costs will be allocated based on the Delivery Services Gross Plant Ratio.

*aa) Energy Delivery Engineering/Design**

Description - Provides engineering and design services in support of capacity planning, construction, operations and material standards.

Method of Allocation - Energy Delivery Engineering/Design services will be direct charged; administrative support functions that cannot be direct charged will be allocated based on the Delivery Services Gross Plant ratios based on the services being provided.

*bb) Marketing & Sales**

Description - Provides marketing and sales services for the Operating Companies and affiliates for their electric and natural gas customers including strategic planning, segment identification, business analysis, sales planning and customer service.

Method of Allocation - Marketing & Sales indirect costs will be allocated based on the Revenue Ratio.

*cc) Customer Service**

Description - Provides service activities to retail and wholesale customers. These services include meter reading, customer billing, call center and credit and collections.

Method of Allocation - Customer Service indirect costs will be allocated based on the Customers Ratio. Indirect costs associated with administering low income and certified medical customer assistance programs will be allocated based on a composite of the Average of the Special Needs Customer Contacts Ratio and residential Customers Ratio.

*dd) Business Systems**

Description - Provides basic information technology services such as: application management, voice and data network operations and management, customer support services, problem management services, security administration and systems management. In addition, Business Systems acts as a single point of contact for delivery of all technical services to Xcel Energy. They partner with vendors to ensure the delivery of benchmarking, continuous improvement, and leadership around strategic initiatives and key developments in the marketplace.

Method of Allocation - Business Systems indirect costs will be allocated using any of the allocation ratios or combination of ratios.

*ee) Aviation Services**

Description - Provides aviation and travel services to employees.

Method of Allocation - Aviation Services will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio, and the Total Assets Ratio.

*ff) Fleet**

Description - Oversees the Operating Companies' Fleet Services Group.

Method of Allocation - Fleet will be direct charged.

*Corporate Governance activities within this Service Function will be allocated using the average of the Assets Ratio including Xcel Energy Inc.'s per book assets, Revenue Ratio with intercompany dividends assigned to Xcel Energy Inc., and Employee Ratio with number of common officers assigned to Xcel Energy Inc.

Allocation Ratios

The following ratios will be utilized as outlined above.

Revenue Ratio - Based on the sum of the monthly revenue amounts for the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Revenue Ratio with intercompany dividends assigned to Xcel Energy Inc. - Based on the sum of the monthly revenue amounts for the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. Xcel Energy Inc. will be assigned the amount of intercompany dividends. This ratio will be determined annually, or at such time as may be required due to significant changes.

Employee Ratio - Based on the number of employees at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes. For regulatory purposes, in the Minnesota jurisdiction, the Total Allocated Labor Hours Including Overtime shall be used. Total Allocated Labor Hours Including Overtime (FTE Hours) is the methodology ordered by the Minnesota Public Utilities Commission in Docket No. E,G002/AI-10-690, which is based on the number of labor hours including overtime for employees at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies.

Employee Ratio with number of common officers assigned to Xcel Energy Inc. - Based on the number of employees at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. Xcel Energy Inc. will be assigned the number of common officers. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total Assets Ratio - Based on the total assets as of December 31 for the prior year, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Square Footage Ratio - Based on the total square footage as of December 31 for the prior year. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Invoice Transaction Ratio - Based on the sum of the monthly number of invoice transactions processed for the prior year ending December 31. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually or at such time as may be required due to significant changes.

Customer Bills Ratio - Based on the average of the monthly total number of customer bills issued during the prior year ending December 31. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

MWh Generation Ratio - Based on the sum of the monthly electric MWh generated by type of generator during the prior year ending December 31, the numerator of which is for an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total MWh Sales Ratio - Based on the sum of the monthly electric MWh hours sold during the prior year ending December 31, the numerator of which is for an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This includes sales to ultimate customers, wholesale customers, and non-requirement sales for resale. This ratio will be determined annually, or at such time as may be required due to significant changes.

Customers Ratio - Based on the average of the monthly total electric customers (and/or gas customers, or residential, business and large commercial and industrial customers, where applicable) for the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Delivery Services Gross Plant Ratio - Based on transmission and distribution gross plant for the Delivery Business unit, both electric and gas or as may be applicable Electric Distribution, for the prior year ending December 31. The numerator of which is an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Provided, however, as follows:
(1) If the costs being allocated are directly related only to electric transmission, the ratio shall be based on the electric transmission gross plant;
(2) If the costs being allocated are directly related only to electric distribution, the ratio shall be based on the electric distribution gross plant;
(3) If the costs being allocated are directly related only to gas transmission, the ratio shall be based on the gas transmission gross plant;
(4) If the costs being allocated are directly related only to gas distribution, the ratio shall be based on the gas distribution gross plant;
(5) If the costs being allocated are directly related only to electric transmission and electric distribution, the ratio shall be based on the sum of the electric transmission gross plant and the electric distribution gross plant;
(6) If the costs being allocated are directly related only to electric transmission and gas transmission, the ratio shall be based on the sum of the electric transmission gross plant and the gas transmission gross plant;
(7) If the costs being allocated are directly related only to electric transmission and gas distribution, the ratio shall be based on the sum of the electric transmission gross plant and the gas distribution gross plant;
(8) If the costs being allocated are directly related only to electric distribution and gas transmission, the ratio shall be based on the sum of the electric distribution gross plant and the gas transmission gross plant;
(9) If the costs being allocated are directly related only to electric distribution and gas distribution, the ratio shall be based on the sum of the electric distribution gross plant and the gas distribution gross plant;
(10) If the costs being allocated are directly related only to gas transmission and gas distribution, the ratio shall be based on the sum of the gas transmission gross plant and the gas distribution gross plant;
(11) If the costs being allocated are directly related only to electric transmission, electric distribution, and gas transmission, the ratio shall be based on the sum of the electric transmission gross plant, the electric distribution gross plant, and the gas transmission gross plant;
(12) If the costs being allocated are directly related only to electric

transmission, electric distribution, and gas distribution, the ratio shall be based on the sum of the electric transmission gross plant, the electric distribution gross plant, and the gas distribution gross plant;
(13) If the costs being allocated are directly related only to electric transmission, gas transmission, and gas distribution, the ratio shall be based on the sum of the electric transmission gross plant, the gas transmission gross plant, and the gas distribution gross plant;
(14) If the costs being allocated are directly related only to electric distribution, gas transmission, and gas distribution, the ratio shall be based on the sum of the electric distribution plant, the gas transmission gross plant, and the gas distribution gross plant.

Meters Ratio - Based on the number of meters at the end of the prior year ending December 31. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Customer Contacts Ratio - Based on the total annual number of customer contacts at the end of the prior year ending December 31. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratiowill be determined annually, or at such a time as may be required due to significant changes.

If the costs being allocated are directly related only to the support of special needs customers, such as those receiving low income energy assistance and those having certified medical conditions, the Special Needs Customer Contacts Ratio shall be used.

Special Needs Customer Contacts Ratio – Based on the number of contacts received by the special needs customer department at the end of the prior year ending December 31. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Accounts Payable Transactions Ratio - Based on the total annual number of accounts payable transactions by system application at the end of the prior year ending December 31. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Inventory Transactions Ratio - Based on the total annual number of inventory transactions by system application at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Work Management Transactions Ratio - Based on the total annual number of work management transactions by system application at the end of the prior year ending December 31. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Purchasing Transactions Ratio - Based on the total annual number of purchasing transactions by system application at the end of the prior year ending December 31. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Total Plant Ratio - Based on total property, plant and equipment at the end of the prior year ending December 31. The numerator of which is an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Provided, however, as follows:
(1) If the costs being allocated are directly related only to electric production, the ratio shall be based on the total electric production plant;
(2) If the costs being allocated are directly related only to electric transmission, the ratio shall be based on the total electric transmission plant;
(3) If the costs being allocated are directly related only to electric distribution, the ratio shall be based on the total electric distribution plant;
(4) If the costs being allocated are directly related only to gas transmission, the ratio shall be based on the total gas transmission plant;
(5) If the costs being allocated are directly related only to gas distribution, the ratio shall be based on the total gas distribution plant;
(6) If the costs being allocated are directly related only to intangible plant, the ratio shall be based on the total intangible plant;
(7) If the costs being allocated are directly related only to electric

production and electric transmission, the ratio shall be based on the sum of the total electric production plant and the total electric transmission plant;
(8) If the costs being allocated are directly related only to electric production and electric distribution, the ratio shall be based on the sum of the total electric production plant and the total electric distribution plant;
(9) If the costs being allocated are directly related only to electric production and gas transmission, the ratio shall be based on the sum of the total electric production plant and the total gas transmission plant;
(10) If the costs being allocated are directly related only to electric production and gas distribution, the ratio shall be based on the sum of the total electric production plant and the total gas distribution plant;
(11) If the costs being allocated are directly related only to electric production and intangible plant, the ratio shall be based on the sum of the total electric production plant and the total intangible plant;
(12) If the costs being allocated are directly related only to electric transmission and electric distribution, the ratio shall be based on the sum of the total electric transmission plant and the total electric distribution plant;
(13) If the costs being allocated are directly related only to electric transmission and gas transmission, the ratio shall be based on the sum of the total electric transmission plant and the total gas transmission plant;
(14) If the costs being allocated are directly related only to electric transmission and gas distribution, the ratio shall be based on the sum of the total electric transmission plant and the total gas distribution plant;
(15) If the costs being allocated are directly related only to electric transmission and intangible plant, the ratio shall be based on the sum of the total electric transmission plant and the total intangible plant;
(16) If the costs being allocated are directly related only to electric distribution and gas transmission, the ratio shall be based on the sum of the total electric distribution plant and the total gas transmission plant;
(17) If the costs being allocated are directly related only to electric distribution and gas distribution, the ratio shall be based on the sum of the total electric distribution plant and the total gas distribution plant;
(18) If the costs being allocated are directly related only to electric distribution and intangible plant, the ratio shall be based on the sum of the total electric distribution plant and the total intangible plant;
(19) If the costs being allocated are directly related only to gas transmission and gas distribution, the ratio shall be based on the sum of the total gas transmission plant and the total gas distribution plant;
(20) If the costs being allocated are directly related only to gas transmission and intangible plant, the ratio shall be based on the sum of the total gas transmission plant and the total intangible plant;
(21) If the costs being allocated are directly related only to gas distribution and intangible plant, the ratio shall be based on the sum of the total gas distribution plant and the total intangible plant;

(22) If the costs being allocated are directly related only to electric production, electric transmission, and electric distribution, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, and the total electric distribution plant;
(23) If the costs being allocated are directly related only to electric production, electric transmission, and gas transmission, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, and the total gas transmission plant;
(24) If the costs being allocated are directly related only to electric production, electric transmission, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, and the total gas distribution plant;
(25) If the costs being allocated are directly related only to electric production, electric transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, and the total intangible plant;
(26) If the costs being allocated are directly related only to electric production, electric distribution, and gas transmission, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, and the total gas transmission plant;
(27) If the costs being allocated are directly related only to electric production, electric distribution, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, and the total gas distribution plant;
(28) If the costs being allocated are directly related only to electric production, electric distribution, and intangible, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, and the total intangible plant;
(29) If the costs being allocated are directly related only to electric production, gas transmission, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total gas transmission plant, and the total gas distribution plant;
(30) If the costs being allocated are directly related only to electric production, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total gas transmission plant, and the total intangible plant;
(31) If the costs being allocated are directly related only to electric production, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total gas distribution plant, and the total intangible plant;
(32) If the costs being allocated are directly related only to electric transmission, electric distribution, and gas transmission, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, and the total gas transmission plant;
(33) If the costs being allocated are directly related only to electric transmission, electric distribution, and gas distribution, the ratio shall be

based on the sum of the total electric transmission plant, the total electric distribution plant, and the total gas distribution plant;

(34) If the costs being allocated are directly related only to electric transmission, electric distribution, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, and the total intangible plant;

(35) If the costs being allocated are directly related only to electric transmission, gas transmission, and gas distribution, the ratio shall be based on the sum of the total electric transmission plant, the total gas transmission plant, and the total gas distribution plant;

(36) If the costs being allocated are directly related only to electric transmission, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total gas transmission plant, and the total intangible plant;

(37) If the costs being allocated are directly related only to electric transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total gas distribution plant, and the total intangible plant;

(38) If the costs being allocated are directly related only to electric distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric distribution plant, the total gas transmission plant, and the total intangible plant;

(39) If the costs being allocated are directly related only to electric distribution, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric distribution plant, the total gas distribution plant, and the total intangible plant;

(40) If the costs being allocated are directly related only to electric distribution, gas distribution, and gas transmission, the ratio shall be based on the sum of the total electric distribution plant, the total gas distribution plant, and the total gas transmission plant;

(41) If the costs being allocated are directly related only to gas transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total gas transmission plant, the total gas distribution plant, and the total intangible plant;

(42) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, and gas transmission, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, and the total gas transmission plant;

(43) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, and the total gas distribution plant;

(44) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, and intangible plant,

the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, and the total intangible plant;
(45) If the costs being allocated are directly related only to electric production, electric transmission, gas transmission, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total gas transmission plant, and the total gas distribution plant;
(46) If the costs being allocated are directly related only to electric production, electric transmission, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total gas transmission plant, and the total intangible plant;
(47) If the costs being allocated are directly related only to electric production, electric distribution, gas transmission, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, the total gas transmission plant, and the total gas distribution plant;
(48) If the costs being allocated are directly related only to electric production, electric distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, the total gas transmission plant, and the total intangible plant;
(49) If the costs being allocated are directly related only to electric production, electric distribution, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, the total gas distribution plant, and the total intangible plant;
(50) If the costs being allocated are directly related only to electric production, gas transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total gas transmission plant, the total gas distribution plant, and the total intangible plant;
(51) If the costs being allocated are directly related only to electric transmission, electric distribution, gas transmission, and gas distribution, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, the total gas transmission plant, and the total gas distribution plant;
(52) If the costs being allocated are directly related only to electric transmission, electric distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, the total gas transmission plant, and the total intangible plant;
(53) If the costs being allocated are directly related only to electric transmission, electric distribution, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the

total electric distribution plant, the total gas distribution plant, and the total intangible plant;
(54) If the costs being allocated are directly related only to electric transmission, gas transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total gas transmission plant, the total gas distribution plant, and the total intangible plant;
(55) If the costs being allocated are directly related only to electric distribution, gas transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric distribution plant, the total gas transmission plant, the total gas distribution plant, and the total intangible plant;
(56) If the costs being allocated are directly related only to electric production, electric transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total gas distribution plant, and the total intangible plant;
(57) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, gas distribution, and gas transmission, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, the total gas distribution plant, and the total gas transmission plant;
(58) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, the total gas transmission plant, and the total intangible plant;
(59) If the costs being allocated are directly related only to electric production, electric distribution, gas distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, the total gas distribution plant, the total gas transmission plant, and the total intangible plant;
(60) If the costs being allocated are directly related only to electric production, electric transmission, gas distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total gas distribution plant, the total gas transmission plant, and the total intangible plant;
(61) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, the total gas distribution plant, and the total intangible

plant;
(62) If the costs being allocated are directly related only to electric transmission, electric distribution, gas distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, the total gas distribution plant, the total gas transmission plant, and the total intangible plant.

Total Phones Ratio - Based on the number of phones at the end of the prior year ending December 31. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Total Radios Ratio - Based on the number of radios at the end of the prior year ending December 31. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Total Computers Ratio - Based on the number of computers at the end of the prior year ending December 31. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Total Software Applications Users Ratio - Based on the number of users of a specific software application at the end of the prior year ending December 31. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Joint Operating Agreement Peak Hour Megawatt Load Ratio - Based on that certain Joint Operating Agreement among Northern States Power Company, a Minnesota corporation, Northern States Power Company, a Wisconsin corporation, Public Service Company of Colorado, Southwestern Public Service Company, and Xcel Energy Services Inc., as agent, dated as of October 1, 2004, as may be amended from time to time, that designates costs to be allocated based on peak hour of megawatt load for previous year ending December 31. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Joint Operating Agreement Labor Hours Ratio - Based on that certain Joint Operating Agreement among Northern States Power Company, a Minnesota corporation, Northern States Power Company, a Wisconsin corporation, Public Service Company of Colorado, Southwestern Public Service Company, and Xcel Energy Services Inc., as agent, dated as of October 1, 2004, as may be amended from time to time, that designates costs to be allocated based on labor hours at the end of the prior year ending December 31. The numerator of which is for an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Direct Labor Ratio – Based on fully-loaded direct-charged Rates and Regulation labor dollars charged to individual operating affiliates by the Rates and Regulation service function. The numerator of which is the fully-loaded direct-charged labor dollars to individual operating affiliates by the Rates and Regulation service function and the denominator of which is the total fully-loaded direct-charged labor dollars to all affiliates by the Rates and Regulation service function.

Northern States Power Company

Cost Assignment and Allocation Manual

September 2019

Table of Contents

Section

I. INTRODUCTION

This Cost Assignment and Allocation Manual ("CAAM") was developed to specify the procedures that Northern States Power Company ("NSPM" or the "Company") follows in assigning and allocating costs among utility departments (electric and gas), among regulated services and non-regulated business activities and among jurisdictions.

NSPM was incorporated in 2000 under the laws of Minnesota and is a wholly owned operating utility subsidiary of Xcel Energy Inc. ("Xcel Energy" or the "Parent"). Xcel Energy was initially established as a registered holding company under the Public Utility Holding Company Act of 1935 ("PUHCA 1935"), with oversight by the Securities and Exchange Commission ("SEC"). On August 8, 2005, the Energy Policy Act of 2005 was signed into law. This repealed PUHCA 1935 and enacted the Public Utility Holding Company Act of 2005 ("PUHCA 2005"), which became effective on February 8, 2006. Responsibility for oversight of public utility holding companies was transferred from the SEC to the Federal Energy Regulatory Commission ("FERC") as a result of the Energy Policy Act of 2005.

NSPM is engaged in the generation, purchase, transmission, distribution and sale of electricity in Minnesota, North Dakota, and South Dakota. NSPM also purchases, transports, distributes, and sells natural gas to retail customers and transports customer-owned natural gas in Minnesota and North Dakota.

NSPM owns the following direct subsidiaries: Blazing Star Wind Farm 2, LLC; Dakota Range I, LLC; Dakota Range II, LLC; Freeborn Wind energy LLC; United Power and Land Company, which holds real estate; and NSP Nuclear Corporation.

As a member of a holding company system, NSPM receives administrative, management, environmental, and other support services from Xcel Energy Services Inc. ("XES" or the "Service Company"), a centralized service company. Service Company provides services to the Xcel Energy, at cost, pursuant to service agreements. The service agreement between NSPM and XES, including all amendments to the original Service Agreement, have been submitted to, and approved by, the Minnesota Public Utilities Commission ("Commission"). The cost allocation methodologies under which XES costs are assigned and allocated are set forth in that Commission approved service agreement, and while those allocation methodologies are not the subject of this NSPM CAAM, they are referenced in several sections herein.

The Service Company is referenced in the CAAM for the following reasons:

- The Service Company is listed as an affiliate company in the Transaction with Affiliates section for the services it provides to NSPM.
- The Service Company and all other companies in the Xcel Energy holding company system of companies are included in the Corporate Organization section to provide a listing of all affiliates of NSPM.
- The Service Company is referenced in the Cost Assignment and Allocation Process section because this section covers processes that may cross multiple legal entities.

The NSPM CAAM contains the following sections:

- Introduction (Section I)
- Corporate Organization (Section II)
- Description of Services (Section III)
- Transactions with Affiliates (Section IV)
- Cost Assignment and Allocation Process (Section V)
- Utility Allocations (Section VI)
- Non-regulated Business Activity Allocations (Sections VII)
- Jurisdictional Allocations (Section VIII)

DEFINITIONS

Abbreviations or Acronyms

The following abbreviations or acronyms are used within the CAAM document:

A&G	Administrative and general
AFUDC	Allowance for funds used during construction
ACC	Allocating cost center
CAAM	Cost Assignment & Allocation Manual
CIP	Conservation improvement program
Commission	Minnesota Public Utilities Commission
FERC	Federal Energy Regulatory Commission
FICA	Federal Insurance Contributions Act
FUTA	Federal Unemployment Tax Act
GAAP	Generally Accepted Accounting Principals
HR	Human Resources
IT	Information Technology
NSPM or the Company	Norther States Power Company, a Minnesota corporation
NSPW	Northern States Power Company, a Wisconsin corporation
O&M	Operations and maintenance
PSCo	Public Service Company of Colorado, a Colorado corporation
RTU	Remote terminal unit
SAP	SAP general ledger and work and asset management system
SCADA	Supervisory control and data acquisition
SEC	Securities and Exchange Commission
SKF	Statistical key figure
SPS	Southwestern Public Service Company, a New Mexico corporation
SUTA	State Unemployment Tax Authority
Utility subsidiaries or operating companies	NSPM, NSPW, PSCo, and SPS
UMP	Utility money pool
Xcel Energy or the Parent	Xcel Energy Inc. and its subsidiaries
XES or the Service Company	Xcel Energy Services Inc.

Terms

The following terms are used within the CAAM document:

Accounts Payable – the payment and reporting department of XES.

A&G – includes activity in FERC accounts 920-935, Administrative and General Expenses.

ACC – an organizational unit that collects cost to be allocated using the allocation ratios or factors included in the SKF.

Assessment – the process used by the accounting system to allocate costs from an ACC to the receiving cost element.

Cost Element – an organizational unit to SAP that is used to track costs in the accounting system as they move through the various processing steps.

Customer Accounting Costs – includes activity in FERC accounts 901-903, Customer Accounts Expenses; FERC accounts 906-910, Customer Service and Informational Expenses; and FERC accounts 911-917, Sales Expenses.

Final Cost Center – final cost center defined by business function, company code, and profit center.

Home Cost Center – captures only labor and payroll postings and maps to HR departments.

Internal Order – internal orders are accounting mechanisms used to track expenses associated with certain projects or functions.

Non-Operations and Maintenance Allocations – allocations designed to apportion expenses recorded in accounts other than O&M to electric, gas, thermal and nonutility. The non-O&M costs apportioned include depreciation, payroll taxes, miscellaneous service revenues, amortization expenses, etc.

O&M – includes activity in FERC accounts 500-935 with the exception of the following FERC accounts: 501, Fuel; 901-903, Customer Accounts Expenses; 906-910, Customer Service and Informational Expenses; 911-917, Sales Expenses; and 920-935, Administrative and General Expenses.

Profit Center – SAP data element that identifies the jurisdiction or joint venture owner of revenues and expenses.

Receiving Cost Element –a cost element that receives costs when a settlement or assessment process is run.

Segment – represents electric, gas, thermal, joint venture, or other and is derived by SAP from profit center and cost center.

SKF – the method by which the allocation ratios and factors are organized in the accounting system and linked to ACCs to facilitate the performance of the assessment process to allocate charges.

Supply Chain – the supply chain department of XES.

Work Breakdown Structure – structure used to group all aspects or phases of a given project or organizational group, and render them easily reportable.

II. CORPORATE ORGANIZATION

OVERVIEW OF COMPANY SYSTEM

Xcel Energy Inc., a Minnesota corporation, is a registered holding company. The Parent directly owns the utility subsidiaries that serve electric, natural gas, thermal, and propane customers in eight states. These four utility subsidiaries are Northern States Power Company, a Minnesota corporation ("NSPM"); Northern States Power Company, a Wisconsin corporation ("NSPW"); Public Service Company of Colorado, a Colorado corporation ("PSCo"); and Southwestern Public Service Company, a New Mexico corporation ("SPS"). Xcel Energy is also the parent company of WestGas InterState, Inc., an interstate natural gas pipeline company and three transmission-only operating companies, Xcel Energy Southwest Transmission Company, LLC ("XEST"), Xcel Energy Transmission Development Company, LLC ("XETD"), and Xcel Energy West Transmission Company, LLC ("XEWT"), all of which are regulated, or expected to be regulated by the FERC. Their collective service territories include portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas, and Wisconsin.

Xcel Energy owns the following additional direct subsidiaries, some of which are intermediate holding companies with additional subsidiaries: Xcel Energy Wholesale Group Inc., Xcel Energy Markets Holdings Inc., Xcel Energy International Inc., Xcel Energy Ventures Inc., Xcel Energy Retail Holdings Inc., Xcel Energy Communications Group Inc., , Xcel Energy WYCO Inc., Xcel Energy Transmission Holding Company, LLC, Xcel Energy Venture Holdings, Inc., Nicollet Holdings Company, LLC, and Xcel Energy Services Inc. Xcel Energy and its subsidiaries collectively are referred to as Xcel Energy Inc., and many do business under the Xcel Energy name. See the following pages for a complete legal entity organizational listing for Xcel Energy Inc. and its subsidiaries.

LIST OF REGULATED & NON-REGULATED AFFILIATES (as of June 30, 2019)

Xcel Energy Inc.
- Northern States Power Company, a Minnesota corporation
  - Blazing Star Wind Farm 2, LLC
  - Dakota Range I, LLC
  - Dakota Range II, LLC
  - Freeborn Wind Energy LLC
  - NSP Nuclear Corporation
  - Private Fuel Storage LLC
  - United Power and Land Company
- Northern States Power Company, a Wisconsin corporation
  - Chippewa and Flambeau Improvement Company
  - Clearwater Investments, Inc.
    - Shoe Factory Holding LLC
  - NSP Lands, Inc.
- Public Service Company of Colorado, a Colorado corporation**
  - 1480 Welton, Inc.
  - Beeman Irrigating Ditch and Milling Company

- Cheyenne Ridge Wind Project, LLC
- Consolidated Extension Canal Company
- East Boulder Ditch Company
- Fisher Ditch Company
- Gardeners Mutual Ditch Company
- Green and Clear Lakes Company
- Hillcrest Ditch and Reservoir Company
- Las Animas Consolidated Canal Company
- P.S.R. Investments, Inc.
- United Water Company

Southwestern Public Service Company, a New Mexico corporation
- Hale Petersburg Wind, LLC

Nicollet Holdings Company, LLC
- Capital Services, LLC

Nicollet Project Holdings, LLC
- Nicollet Projects I, LLC
  - Betcher CSG LLC
  - Foreman's Hill CSG LLC
  - Grimm CSG LLC
  - Heyer CSG LLC
  - Huneke CSG LLC
  - Johnson I CSG LLC
  - Johnson II CSG LLC
  - Krause CSG LLC
  - RJC I CSG LLC
  - RJC II CSG LLC
  - Scandia CSG LLC
  - School Sisters CSG LLC
  - Webster CSG LLC
- Nicollet Projects II, LLC

WestGas InterState, Inc.

Xcel Energy Foundation

Xcel Energy Communications Group Inc.
- Seren Innovations, Inc.

Xcel Energy International Inc.*

Xcel Energy Markets Holdings Inc.
- e prime, inc.*
- Young Gas Storage Company Ltd.

Xcel Energy Retail Holdings Inc.
- Xcel Energy Performance Contracting Inc.
- Reddy Kilowatt Corporation

Xcel Energy Services Inc.

Xcel Energy Transmission Holding Company, LLC
- Xcel Energy Southwest Transmission Company, LLC
- Xcel Energy Transmission Development Company, LLC
  - Xcel Energy Acorn Transmission, LLC
  - Xcel Energy Birch Transmission, LLC
- Xcel Energy West Transmission Company, LLC

- Xcel Energy Venture Holdings, Inc.
  - Energy Impact Fund Investment LLC
  - Xcel Energy Investments, LLC
- Xcel Energy Ventures Inc.
  - Eloigne Company
    - Bemidji Townhouse LP
    - Chaska Brickstone LP
    - Crown Ridge Apartments LP
    - Cottage Court LP
    - Dakotah Pioneer LP
    - Edenvale Family Housing LP
    - Fairview Ridge LP
    - Farmington Family Housing LP
    - Farmington Townhome LP
    - Hearthstone Village LP
    - J&D 14-93 LP
    - Lauring Green LP
    - Links Lane LP
    - Lyndale Avenue Townhomes LP
    - Mahtomedi Woodland LP
    - Mankato Townhomes LLP
    - Marvin Garden LP
    - Moorhead Townhomes LP
    - Park Rapids Townhomes LP
    - Rochester Townhome LP
    - Rushford Housing LP
    - Safe Haven Homes, LLC
    - Shade Tree Apartments LP
    - Shakopee Boulder Ridge LP
    - Shenandoah Woods LP
    - Sioux Falls Partners LP
    - St. Cloud Housing LP
    - Tower Terrace LP
- Xcel Energy Wholesale Group Inc.*
  - Quixx Corporation*
    - Quixx Carolina, Inc.*
    - Quixxlin Corp.*
- Xcel Energy WYCO Inc.
  - WYCO Development, LLC

* Company is being classified in discontinued operations.
** Minority-ownership ditch and water companies have been excluded.

III. DESCRIPTION OF SERVICES

OVERVIEW

The following pages provide a description of NSPM's regulated services and non-regulated business activities. Each description identifies the types of costs associated with each service or business activity, and identifies the business area or department which offers the service.

REGULATED SERVICES

ELECTRIC UTILITY

Electric – Residential

Residential electric service represents the provision of electric service to residential customers within the NSPM service territory. Costs associated with this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Electric – Commercial and Industrial

Commercial and industrial electric service represents the provision of electric service to commercial and industrial customers within the NSPM service territory. Costs associated with this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Electric – Street Lighting

Street lighting electric service represents the provision of electric service to public authorities for lighting streets, highways, parks and other public places, or for traffic or other signal system service through Company-owned or customer-owned lighting equipment. Costs associated with this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Electric – Other Sales to Public Authorities

Other sales to public authorities' electric service represent the provision of electric service to public authorities under special agreements or contracts. Costs associated with this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Electric - Resale

Resale electric service represents the provision of electric service to NSPM wholesale customers or public authorities for resale to end-user customers or to power marketers. Costs associated with this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, or through facilities owned by third parties, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Electric - Interdepartmental

Interdepartmental electric service represents the provision of electric service to NSPM company facilities at tariff rates. Costs associated with providing this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Off-System Electric Sales

NSPM sells electricity not required to serve its native load to off-system customers. Costs related to this activity can include fuel and purchased power costs. The revenues associated with these sales reside in FERC account 447, Sales for Resale-Electric. The costs related to this activity reside in FERC accounts 501, Fuel-Steam Generation; 555, Purchased Power; and 565, Transmission of Electricity by Others. In addition, the Company may allocate production O&M and transmission costs based on a percentage of overall sales relative to the type of off-system sales. These costs reside within the NSPM Electric Utility.

OTHER ELECTRIC OPERATING REVENUE

Rent from Electric Property

Rent from electric property results from the leasing of NSPM owned utility property not currently utilized for the provision of regulated services to non-affiliated third parties. Costs related to this service are primarily A&G costs associated with customer billings, as well as rental contract renewals. The revenue associated with the rentals resides in FERC account 454, Rent from Electric Property.

Interchange Agreement

The electric production and transmission costs of the entire NSP System are shared by NSP-Minnesota and NSP-Wisconsin. A FERC-approved Interchange Agreement between the two companies provides for the sharing of all generation and transmission costs of the NSP System based upon demand and energy ratios reflecting usage by the respective companies. The costs associated with this agreement reside in FERC account 557, Other Power Supply Expenses; and FERC 565, Transmission of Electricity by Others. The revenues reside in FERC account 456.1, Revenue from Transmission of Electricity of Others.

Joint Operating Agreement

The Joint Operating Agreement is a margin sharing agreement associated with proprietary energy trading activities. Revenues are recorded in FERC 456, Other Electric Revenues.

Miscellaneous Electric Revenue

In addition to the services detailed above, there are various activities that cannot be accounted for elsewhere, such as utility locating services, scrap metal sales, WindSource, customer connections, and refuse derived fuel incentive. These revenues are recorded in FERC account 456, Other Electric Revenues.

GAS UTILITY

Gas - Residential

Residential gas service represents the provision of natural gas service to residential customers within the NSPM service territory. Costs associated with this service relate to the purchase and delivery of gas through Company-owned facilities, primarily purchased gas, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Gas Utility.

Gas – Commercial and Industrial

Commercial and industrial gas service represents the provision of natural gas service to commercial and industrial customers within the NSPM service territory. Costs associated with this service relate to the purchase and delivery of gas through Company-owned facilities, primarily purchased gas, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Gas Utility. The table below shows the various rate classes within commercial and industrial gas services.

Rate Class	**Maximum Requirements – Daily Therms**	**Maximum Requirements – Annual Therms**
Small commercial	Less than 500	Less than 6,000
Large commercial	Less than 500	Greater than 6,000
Small demand billed commercial*	Less than 500	
Large demand billed commercial*	Greater than 500	

* Upstream demand costs are billed based on the highest one-day usage in the customer's history.

Gas – Interruptible

Interruptible gas service represents the provision of natural gas service to interruptible customers within the NSPM service territory. Interruptible service is subject to curtailment when either additional upstream pipeline or local distribution capacity is needed to ensure service to firm customers. Costs associated with this service relate to the purchase and delivery of gas through Company-owned facilities, primarily purchased gas, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Gas Utility. The table below shows the various rate classes within interruptible gas service.

Rate Class	**Maximum Requirements – Daily Therms**
Small interruptible	Less than 2,000
Medium interruptible	Greater than 2,000 and less than 50,000
Large interruptible	Greater than 50,000

Gas – Large Firm Transportation

Large firm gas transportation service represents the provision of gas delivery service on behalf of end-use customers, third-party suppliers or marketers whereby NSPM transports gas owned by others over NSPM's gas pipeline system. Costs associated with this service primarily include the facilities O&M and depreciation costs and A&G costs. These costs reside within the NSPM Gas Utility.

Gas – Interruptible Transportation

Interruptible gas transportation service represents the provision of gas delivery service on behalf of end-use customers, third-party suppliers or marketers whereby NSPM transports gas owned by others over NSPM's gas pipeline system. Interruptible transportation gas service is subject to curtailment when either additional upstream pipeline or the local distribution capacity is needed to ensure service to firm customers. Costs associated with this service primarily include the facilities O&M and depreciation costs and A&G costs. These costs reside within the NSPM Gas Utility.

Gas – Negotiated Transportation

Negotiated firm and interruptible gas transportation service (bypass customers) represents the provision of gas delivery service on behalf of end-use customers, third-party suppliers or marketers whereby NSPM transports gas owned by others over NSPM's gas pipeline system. Interruptible transportation gas service is subject to curtailment when either additional upstream pipeline or the local distribution capacity is needed to ensure service to firm customers. Costs associated with this service primarily include the facilities O&M and depreciation costs and A&G costs. These costs reside within the NSPM Gas Utility.

Gas – Interdepartmental

Interdepartmental gas service represents the provision of natural gas service or gas transportation service to NSPM company facilities at tariff rates. Costs associated with providing this service relate to the purchase and delivery of gas through NSPM owned facilities, primarily purchased gas, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Gas Utility.

Gas – Limited Firm

Standby gas service represents on-system back-up propane service for interruptible service customers. Costs associated with this service primarily include propane purchases and the facilities O&M. These costs reside within the NSPM Gas Utility.

Gas – Daily Balancing Service

Daily balancing gas service represents a service to transportation customers that allows them to remedy deviations between nominated and delivered gas and gas consumed by the transportation customer. Costs associated with this service primarily include upstream pipeline costs. These costs reside within the NSPM Gas Utility.

OTHER GAS REVENUE

Miscellaneous Gas Revenue

Various services are provided that cannot be accounted for elsewhere such as propane transportation charges and bundled sales. These revenues are recorded in FERC account 495, Other Gas Revenues.

COMMON ELECTRIC AND GAS REVENUE

Late Payments Fees/Miscellaneous Service Revenues

Revenues from the additional charges imposed because of customers failure to pay their bill by specified due date are recorded into FERC account 450, Electric Forfeited Discounts; and FERC account 487, Gas Forfeited Discounts. Miscellaneous customer related revenue, such as service connections and returned check charges, are recorded in FERC account 451, Miscellaneous Electric Service Revenue; and FERC account 488, Miscellaneous Gas Service Revenues.

CIP Incentives

The CIP Incentive is a mechanism established by an April 7, 2000 Order of the Commission that provides utilities with an incentive to increase cost-effective utility investment in conservation improvement programs beyond the spending levels required by Minnesota Statute. The revenues associated with the CIP incentives are identified by unique accounts and are recorded in FERC account 456, Other Electric Revenues; and FERC 495, Other Gas Revenues. An adjustment is made to remove these revenues from our cost of service study and they do not impact our revenue requirements.

ConnectSmart

NSPM provides a service for customers moving into or across the region to set up utility service and other subscription services to their homes (e.g., newspaper, local and long-distance telephone, cable TV, etc.). NSPM, through its call center, receives telephone requests for this service, and sends these requests, for a fee, to AllConnect (a third-party contractor) for the coordination of installation of services. Costs related to this activity include direct charges for labor, materials and outside services associated with the service provided. In addition, payroll taxes, lost time, facilities, workers' compensation, incentive, pension, and benefit costs are allocated based on labor dollars. The revenues and costs associated with this service are identified by unique accounts, and are recorded in FERC 417, Revenues from Nonutility Operations; and FERC 417.1, Expenses from Nonutility Operations. For rate making purposes, in the event this service experiences revenues in excess of direct expenses, an adjustment is made to credit the net impact in FERC 456, Other Electric Operating Revenues, to reflect the benefit of this service to the utility customers.

Hazardous Waste Disposal

NSPM has a Hazardous Waste consolidation facility at Chestnut Service Center in Minneapolis, Minnesota. The facility accepts and consolidates hazardous and specially-regulated waste materials from generating assets, service centers, substations, office buildings, and field operations projects in both NSPM and NSPW service territories. This facility ensures the wastes are properly characterized aggregated and consolidated at approved, permanent and appropriately licensed waste disposal facilities. This facility is also the central collection point for any PCB contaminated electrical equipment.

NON-REGULATED BUSINESS ACTIVITIES

The following business activities have been approved by the Commission as non-regulated business activities. Detailed descriptions of each of the non-regulated business activities are provided in this section.

HomeSmart

HomeSmart from Xcel Energy offers appliance repair services, heating and cooling equipment sales, and installation. HomeSmart's appliance protection services include appliance repair plans, replacement assistance coverage, and an annual maintenance check. Extended coverage is also available for appliances such as dishwashers, gas fireplaces, and ranges. Costs related to these activities include direct charges for labor, materials, and outside services associated with the services provided. In addition, payroll taxes, lost time, and pension and benefit costs are allocated based on labor dollars, and a labor related overhead and a corporate residual overhead are applied to non-regulated business activities. (Please refer to Section VIII of the CAAM for more information.) The revenues and costs associated with HomeSmart are identified by unique accounts and are recorded in FERC 417, Revenues from Nonutility Operations; and FERC 417.1, Expenses from Nonutility Operations.

Customer Owned Street Lighting Maintenance

NSPM supplies maintenance services for communities that own their own street light systems. Maintenance service for customer owned street light systems is limited to the fixture service only; and ranges from full fixture service to partial fixture service where the customer provides the material necessary to repair the street light. The customer is responsible for all other repairs and replacements under the "Non-regulated Customer Owned Street Maintenance" service. Costs related to this activity include labor and materials associated with the service provided. In addition, payroll taxes, lost time, and pension and benefit costs are allocated based on labor dollars, and a labor related overhead and a corporate residual overhead are applied to non-regulated business activities. The revenues and costs associated with this service are identified by unique accounts and are recorded in FERC 417, Revenues from Nonutility Operations; and FERC 417.1, Expenses from Nonutility Operations. See Docket E-002/M-92-614 for the Commission order to treat this service as non-regulated.

Sherco Steam Sales to Liberty Paper Inc.

NSPM supplies steam from the Sherburne County Generating Station to Liberty Paper, Inc. ("LPI") in order to meet LPI's thermal energy needs. The revenues and costs associated with this service are identified by unique accounts, and are recorded in FERC 417, Revenues from Nonutility Operations; and FERC 417.1, Expenses from Nonutility Operations. See Docket E002/M-93-1253 for the Commission order to treat this service as non-regulated.

InfoWise GX Meter

InfoWise GX Meter is an energy management reporting solution with customized data for businesses to help manage and control their energy use. This product consists of unique interactive monthly reports with detailed information, including both consumption and demand levels, to help the customer pinpoint and analyze their facility's energy use. By analyzing past energy use, this products can help drive company green strategies while helping customize a strategic business plan for facility managers, as well as deliver a bill estimator tool that keeps track of budgets and identifies cost saving opportunities. Costs related to this activity include direct charges for labor, materials and outside services associated with the service provided. In addition, payroll taxes, lost time, facilities, workers' compensation, incentive and pension and benefits are allocated based on labor dollars. Common A&G costs are allocated to the activity based on labor dollars, and common customer accounting costs are allocated to the activity based on revenue dollars. The revenues and costs associated with this service are identified by unique SAP Cost Centers, and are recorded in FERC accounts 417, Revenues from Nonutility Operations, and 417.1, Expenses from Non-utility Operations.

IV. TRANSACTIONS WITH AFFILIATES

OVERVIEW

NSPM directly incurs and pays for the majority of its costs, there are, however, services provided to NSPM by other affiliates within the Xcel Energy system of companies. In addition, NSPM provides a limited amount of operations, maintenance, and management advisory services to its affiliates. NSPM has numerous Affiliated Interest Agreements that have been approved by the Commission.

The sections below separately detail the nature and terms of transactions for services and asset transfers provided by NSPM to its affiliates, as well as services and asset transfers provided to NSPM by each of its affiliates. This section includes descriptions of affiliate transactions only, and does not include convenience payments.

The cost allocation methodologies under which the Service Company costs are assigned and allocated are set forth in the service agreement, and while they are not the subject of this NSPM CAAM, they are included in this section to provide as complete a picture as possible of all affiliate transactions. The NSPM Service Agreement is reviewed and filed annually with the Commission. The last filing was approved in Docket E,G002/AI-19-371 on July 10, 2019. NSPM's affiliate transactions consist primarily of transactions with the Service Company for administrative, management, accounting, legal, engineering, environmental, and other support services.

Terms of Transactions

Tariff Rate – the price charged to customers under applicable tariffs on file with federal or state regulatory commissions. Tariff rates are used for transactions with affiliates involving the provision of regulated services.

Fully Distributed Cost **–** the term fully distributed cost means that transactions billed include all direct and indirect costs, including overheads. Affiliate transactions billed by NSPM include labor related overheads and a working capital fee when appropriate. This method of assigning and allocating costs to these affiliate transactions ensures that the payments to or by NSPM are reasonable and have not resulted in any ratepayer subsidization. In the table below, fully distributed cost may also refer to a price established in a separate Affiliated Interest Agreement.

NSPM applies a labor related overhead to services provided by NSPM to affiliates and also applies a working capital fee on services NSPM provides to non-NSPM company affiliates. Both the labor related overhead and the working capital fees are discussed in Section VII.

The remainder of this section is detailed by affiliate. Affiliates may be listed under the "Services Provided by NSPM to Affiliates" section and/or the "Services Provided by Affiliates to NSPM" section. The details relating to the nature, frequency, and terms of the affiliate transactions are itemized for NSPM and each affiliate.

SERVICES PROVIDED BY NSPM TO AFFILIATES

Nature of Transactions	Terms
NSPW	
O&M – production, decommissioning, and transmission costs associated with the Interchange Agreement (FERC Docket No. ER15-1575-000).	Fully distributed cost
SCADA and Gas Dispatch – sharing of SCADA costs in accordance with Docket G-002/AI-94-831.	Fully distributed cost
Materials and Supplies – materials and supplies, including any associated freight, purchase loadings, and warehouse loadings.	Fully distributed cost
Miscellaneous – miscellaneous other charges, including labor, associated loadings, and lease costs.	Fully distributed cost
PSCo	
Materials and Supplies – materials and supplies, including any associated freight, purchase loadings, and warehouse loadings.	Fully distributed cost
Joint Operating Agreement – margin sharing associated with proprietary energy trading activities.	Fully distributed cost
Miscellaneous – miscellaneous other charges, including labor, associated loadings, and lease costs.	Fully distributed cost
SPS	
Materials and Supplies – materials and supplies, and any associated freight, purchase loadings, and warehouse loadings.	Fully distributed cost
Joint Operating Agreement – margin sharing associated with proprietary energy trading activities.	Fully distributed cost
Miscellaneous – miscellaneous other charges, including labor and associated loadings and lease costs.	Fully distributed cost

Xcel Energy Inc.

Miscellaneous - miscellaneous other charges, including 401(k) match and a dividend on common stock.	Fully distributed cost

SERVICES PROVIDED BY AFFILIATES TO NSPM

Nature of Transactions	*Terms*
Xcel Energy Services Inc.	
*Executive Management Services** – represents charges for executive management services, including, but not limited to, officers of Xcel Energy.	Fully distributed cost
*Investor Relations** – provides communications to investors and the financial community. Coordinates the transfer agent and shareholder record keeping functions and plans the annual shareholder meeting.	Fully distributed cost
*Internal Audit** – reviews internal controls and procedures to ensure assets are safeguarded and transactions are properly authorized and recorded. Evaluates contract risks.	Fully distributed cost
*Legal** – provides legal services related to labor and employment law, litigation, contracts, rates and regulation, environmental matters, real estate, and other legal matters.	Fully distributed cost
*Claims Services** – provides claims services related to casualty, public, and company claims.	Fully distributed cost
*Corporate Communications** – provides corporate communications, speech writing, and coordinates media services. Provides advertising and branding development for Xcel Energy. Provides labor to track all contributions made on behalf of Xcel Energy.	Fully distributed cost
*Employee Communications** – develops and distributes communications to employees.	Fully distributed cost
*Corporate Strategy & Business Development** – facilitates development of corporate strategy and prepares strategic plans, monitors corporate performance, and evaluates business opportunities. Develops and facilitates process improvements.	Fully distributed cost

*Government Affairs** – monitors, reviews and researches government legislation.	Fully distributed cost
*Facilities & Real Estate** – operates and maintains office buildings and service centers. Procures real estate and administers real estate leases. Administers contracts to provide security, housekeeping and maintenance services for such facilities. Procures office furniture and equipment.	Fully distributed cost
*Facilities Administrative Services** – includes but is not limited to the functions of mail delivery, duplicating, and records management.	Fully distributed cost
*Supply Chain**– includes contract negotiations, development and management of supplier relationships, and acquisition of goods and services. Also includes inventory planning and forecasting, ordering, accounting, and database management. Warehousing services includes receiving, storing, issuing, shipping, returns, and distribution of material and parts.	Fully distributed cost
*Supply Chain Special Programs** – develops and implements special programs utilized across Xcel Energy such as procurement cards, travel services, and compliance with corporate MWBE (minority women business expenditures) program goals.	Fully distributed cost
*Human Resources** – establishes and administers policies related to employment, compensation, and benefits. Maintains HR computer system, the tuition reimbursement plan, and diversity program. Coordinates the bargaining strategy and labor agreements with union employees. Provides technical and professional development training and general HR support services.	Fully distributed cost
*Finance & Treasury** – coordinates activities related to securities issuances, including maintaining relationships with financial institutions, cash management, investing activities, and monitoring the capital markets.	Fully distributed cost
*Accounting, Financial Reporting & Taxes** – maintains financial books and records. Prepares financial and statistical reports, tax filings, and ensures compliance with the applicable laws and regulations. Maintains the accounting systems. Coordinates the budgeting process.	Fully distributed cost
*Payment & Reporting** – processes payments to vendors and prepares statistical reports.	Fully distributed cost

*Receipts Processing** – processes payments received from customers of the Utility subsidiaries and affiliates.	Fully distributed cost
*Payroll** – processes payroll including but not limited to time reporting, calculation of salaries and wages, payroll tax reporting, and compliance reports.	Fully distributed cost
*Rates & Regulation** – determines the Utility subsidiaries and affiliates regulatory strategy, revenue requirements, and rates for retail and wholesale customers. Coordinates the regulatory compliance requirements and maintains relationships with the regulatory bodies.	Fully distributed cost
*Energy Supply Engineering and Environmental** – provides engineering services to the generation business. Establishes policies and procedures for compliance with environmental laws and regulations. Researches emerging environmental issues and monitors compliance with environmental requirements. Oversees environmental cleanup projects.	Fully distributed cost
*Energy Supply Business Resources** – provides performance, specialists, and analytical services to the Utility subsidiaries generation facilities.	Fully distributed cost
*Energy Markets Regulated Trading & Marketing** – provides electric trading services to the Utility subsidiaries electric generation systems including load management, system optimization, and resource acquisition.	Fully distributed cost
*Energy Markets-Fuel Procurement** – purchases fuel for Utility subsidiaries electric generation systems (excluding nuclear).	Fully distributed cost
*Energy Delivery Marketing** – develops new business opportunities and markets the products and services for the Delivery business unit.	Fully distributed cost
*Energy Delivery Construction, Operations & Maintenance** – constructs, maintains, and operates electric and gas delivery systems.	Fully distributed cost
*Energy Delivery Engineering/Design** – provides engineering and design services in support of capacity planning, construction, operations, and materials standards.	Fully distributed cost

*Marketing & Sales** – provides marketing and sales services for the Utility subsidiaries and affiliates for their electric and natural gas customers including strategic planning, segment identification, business analysis, sales planning, and customer service.	Fully distributed cost
*Customer Service** – provides service activities to retail and wholesale customers. These services include meter reading, customer billing, call center, and credit and collections.	Fully distributed cost
*Aviation Services** – provides aviation and travel services to employees.	Fully distributed cost
*Fleet** – oversees the Utility subsidiaries Fleet Services business unit.	Fully distributed cost
*Business Systems** – provides basic information technology services such as: application management, voice and data network operations and management, customer support services, problem management services, security administration, and systems management. In addition, Business Systems acts as a single point of contact for delivery of all information technology services to Xcel Energy. Business Systems partner with vendors to ensure the delivery of benchmarking, continuous improvement, and leadership around strategic initiatives and key developments in the marketplace.	Fully distributed cost

** Corporate Governance activities within this service function will be allocated using the average of the revenue ratio with intercompany dividends assigned to Xcel Energy Inc., full time equivalent hours including overtime, and the total assets ratio including Xcel Energy Inc.'s per book assets.*

V. COST ASSIGNMENT AND ALLOCATION PROCESS

OVERVIEW

This section of the CAAM provides an overview of the cost assignment and allocation principles of NSPM and the accounting processes within the monthly accounting close and within the general ledger, including both system generated processes and manual processes, used to assign and allocate costs between the regulated services and the non-regulated business activities of NSPM. Each major step of the accounting process is identified in the following paragraphs and will be explained in conjunction with the process flowchart of this section. Each major step results in costs being either directly assigned or allocated to regulated services and non-regulated business activities. The result of applying these principles is that each company, utility, jurisdiction and non-regulated business activity pays the full cost for any service provided to support their respective operations.

Many of the assignment and allocation processes occur in the Service Company or are administered by Service Company personnel. As noted in the Introduction, the Service Company provides services “at cost” to the Utility subsidiaries and affiliate companies.

The processes discussed in this section are integral to the financial books and records of NSPM and are included to provide a comprehensive picture.

COST ASSIGNMENT AND ALLOCATION PRINCIPLES

NSPM applies the following cost assignment and allocation principles. The cost assignment and allocation approach is a fully distributed costing method as approved by the Commission in NSPM’s electric and gas rates cases (E002/GR-92-1185, G002/GR-92-1186 and G002/GR-97-1606) and the Commission September 28, 1994 Order in Docket G, E-999/CI-90-1008.

The hierarchical cost assignment and allocation principles are:

I. Tariffed rate shall be used to value tariffed services provided.
II. Costs shall be directly assigned to either regulated or non-regulated business activities whenever possible.
III. Costs that cannot be directly assigned to either regulated or non-regulated activities or jurisdictions will be described as common costs. Common costs shall be grouped into homogeneous cost categories designed to facilitate the proper allocation of costs between regulated and non-regulated activities or jurisdictions in accordance with the following principles:
    a. Cost causation. All activities or jurisdictions that cause the cost to be incurred shall be allocated a portion of that cost. Direct assignment of a cost is preferred to the extent that the cost can be traced to the specific activity or jurisdiction.
    b. Variability. If the fully distributed cost study indicates a direct correlation exists between a change and the incurrence of a cost and cost causation, that cost shall be allocated based upon that relationship.

c. Traceability. A cost may be allocated using a measure that has a logical or observable correlation to all the activities or jurisdictions that case the cost to be incurred.
d. Benefit. All activities or jurisdictions that benefit from a cost shall be allocated a portion of that cost.

IV. Residual. The residual of costs left after either direct or indirect assignment or allocation shall be allocated based upon an appropriate general allocator as defined in this CAAM.
V. Whenever neither direct or indirect measures of cost causation can be found, the cost category shall be allocated based upon a general allocator.

A significant portion of NSPM's costs are incurred directly by NSPM. These costs are directly assigned or allocated based on the above principles to utilities, jurisdictions, and to non-regulated business activities. Utility allocations are described in Section VII and jurisdictional allocations are described in Section IX.

ACCOUNTING PROCESSES

The flowchart in this section provides a high level overview of the major steps in the monthly accounting close process and the systems used to generate the financial books and records of NSPM. Several steps within the process have allocations imbedded within and are included to provide as much information as possible to promote an understanding of where direct assignment or allocations can occur.

Feeder Systems (Addendum A, Flowchart Item 1)

The monthly close process initially starts with the collection of accounting information from feeder systems as identified in Item 1 on the flowchart. Feeder systems gather accounting transactions on a daily, weekly or monthly basis and 'feed,' or pass, those accounting transactions to the general ledger within SAP.

SAP General Ledger System Processing (Addendum A, Flowchart Item 2)

Journal entries to record monthly transactions such as interest accruals, amortizations, cash transactions, receivables setup, etc., are entered directly into SAP using the SAP journal entry input screens. These journal entries also include the journal entries to record overheads on non-regulated business activities (see Section VII).

Once all the transactions from the processes identified above are recorded in SAP, there are multiple processing steps within SAP, including settlements and assessments. These processes affect regulated services and non-regulated business activities and are detailed separately on the following pages.

Settlements and Assessments (Addendum A, Flowchart Item 3)

All costs identified as billable are processed using the settlement and/or assessment processes of the SAP system. These processes bill transactions from the legal entity that performed the service to the legal entity that received or is responsible for the service. This process captures:

- Service Company direct and allocated billings of all its costs to affiliated interests;
- Direct billings between a utility subsidiary and an affiliated interest other than the Service Company which are often referred to as intercompany charges or billings; and
- Direct billings between business areas within a legal entity.

For example, the settlements process will settle Service Company labor to the affiliated company if the labor is a direct charge or it will send the charges to an ACC if the charge is to be allocated. The assessment process will then clear the ACC by allocating the charges using an approved method of allocation to the legal entities to which the employee is providing services along with the appropriate labor and labor-related overheads. Transactions between affiliates (excluding XES) are direct charges, as are charges from one business area to another business area (for example, charges from the Distribution Operations business area to the Energy Supply business area). After the settlements and assessment processes are completed, all costs reside on the books of the legal entity ultimately responsible for the charge in the appropriate FERC account.

Business View (Addendum A Flowchart Item 4)

The business view of the SAP general ledger provides a GAAP view of the accounting transactions necessary to prepare SEC financial statements and other GAAP financial reports as well as the information necessary for the business areas to manage the business.

FERC Account Data Prior to Utility and Non-Regulated Allocations (Addendum A Flowchart Item 5)

At the same time that the business view is available, the pre-allocated FERC view of the SAP general ledger is available. The following utility allocations and non-regulated allocations are necessary for common costs to be allocated to the gas, electric, and non-regulated businesses.

Utility Allocations and Non-regulated Allocations (Addendum A, Flowchart Item 6)

NSPM's costs are directly assigned or allocated to electric, gas, or non-regulated business activities whenever possible. When charges can't be directly assigned, they are charged as common and then allocated to the electric and gas utilities using utility allocations. Common utility costs are grouped into two categories: (1) O&M utility allocations and (2) rate base and non-O&M utility allocations. These allocations are performed monthly within the SAP system and are described in Section VII.

In addition to the costs directly assigned to the non-regulated business activities from the Service Company and within NSPM, the non-regulated business activities are charged with a labor related overhead and an allocation of corporate costs. See Section VIII for additional information related to non-regulated business activities.

All costs that can be directly assigned or allocated to the electric or gas utility operations or to the non-regulated business activities are appropriately accounted for in the books and records of NSPM before jurisdictional allocations occur. A study is performed annually, and as required for rate case filing purposes, to identify all rate base and non-O&M costs that are common among the jurisdictions of NSPM (Minnesota, North Dakota, and South Dakota). These costs are then allocated among the jurisdictions according to the allocations described in Section IX.

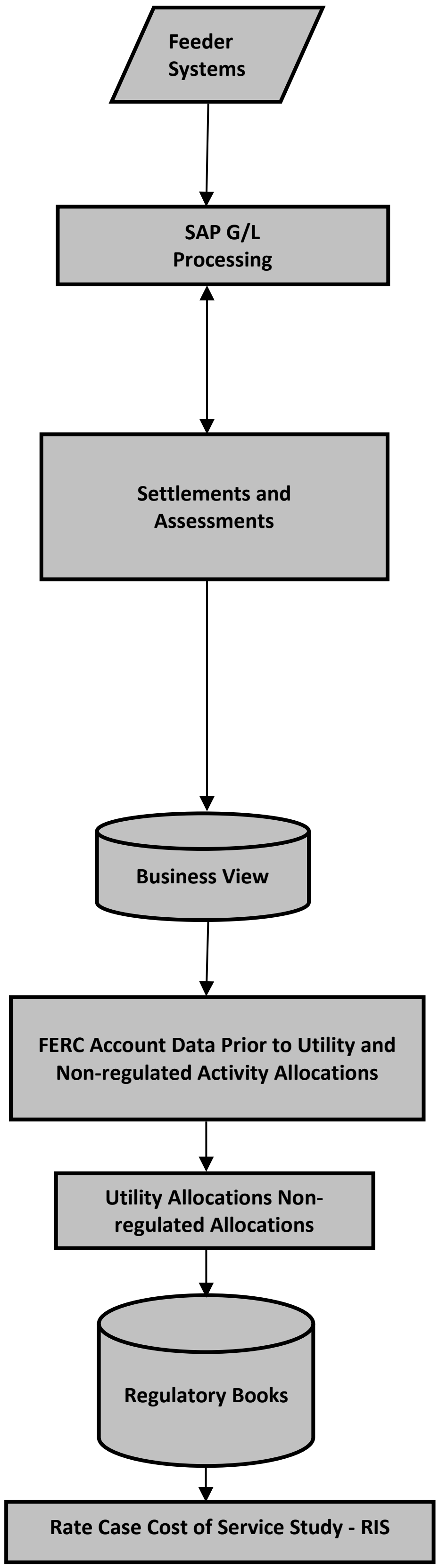
Regulatory Books and Records (Addendum A Flowchart Item 7)

After all the above processes are complete, the result is the FERC financial books and records of NSPM.

Rate Case Cost of Service Study (Addendum A Flowchart Item 8)

The FERC books and records are the starting point for the preparation of a cost of service study that will be used in a gas or electric rate case filing.

ADDENDUM A – PROCESS FLOWCHART



Item 1 – Feeder Systems
- **Labor Distribution**
- **Accounts Payable**
- **Money Pool**
- **Customer Billing**
- **Fixed Asset Ledger**

Item 2 – SAP general ledger system processing

Item 3 – Settlements and Assessments
- **Labor Overheads**
- **Aviation Distribution**
- **Stores/Warehouse Overheads**
- **Purchasing Overheads**
- **Fleet Distribution**
- **Information Technology**
- **Shared Asset Distribution**
- **Facilities Distribution**
- **Engineering & Supervision**
- **Capital A&G**

Item 4 – Business View

Item 5 – FERC account data prior to Utility and Non-regulated activity allocations

Item 6 – Utility Allocations and Non-regulated allocations

Item 7 – Regulated books and records

Item 8 – Rate case cost of service study - Rate Information System (“RIS”)

Feeder and Overhead System Detail

LABOR DISTRIBUTION

Description:	Wages and salaries of employees engaged in work on behalf of regulated services and non-regulated activities are assigned or allocated based on positive time reporting through the labor distribution system. Positive time reporting requires each employee to report the hours worked for each day using one-tenth of an hour or greater increments, while providing for aggregation of time when appropriate. Under this method, employees' time is reported on the basis of accounting codes related to specific operating utility companies or affiliates and/or functional services.
Provider of Service:	Service Company Operating companies or affiliates
User of Service:	Operating companies or affiliates, including utility operations, jurisdictions, and non-regulated activities within an operating company.
Method of Allocation:	All bi-weekly and semi-monthly employees' labor expenses are recorded by company personnel on time sheets and entered into the time reporting system, which feeds into the labor distribution system. The employee submitting the time sheet is responsible for coding the internal order numbers to charge the appropriate operating companies or affiliates, business function (e.g., capital, operations, maintenance, clearing, purchasing and/or warehousing, etc.) and regulated or non-regulated operations. Time must be completed and submitted for review and approval by certain cut-off dates established by the Payroll Department. The employee's supervisor or manager is responsible for reviewing and approving all time entries, and verifying that the employee is using the correct accounting. The labor distribution system used for bi-weekly employees includes the distribution of actual paid and accrued labor dollars/hours to the internal order number charged based on the hours worked. Accrual of payroll is to facilitate the recording of labor costs on a calendar month basis. This includes any reversal of the prior month's accrual. The charge of labor dollars for semi-monthly employees to internal order numbers is based on a distribution of the monthly salary of the employee.

LABOR OVERHEADS

Description:	Employee labor overhead costs are captured in the following categories: Benefit employees: • Non-productive labor costs (vacation, sick, holiday, etc.) • Pension and Insurance (401k match, retirement related consulting, active healthcare, life and LTD insurance premiums, miscellaneous benefit programs and LTD benefits for former or inactive employees before retirement, as well as the service cost portion of qualified pension, non-qualified pension and retiree healthcare) • Benefits Non-Service (non-service cost portion of qualified pension, non-qualified pension and retiree healthcare) • Workers compensation (FAS 112 actuarial cost and insurance premiums) • Incentives (Incentives are a labor overhead for Service Company, PSCo, and SPS. Incentives for NSPM and NSPW are charged directly to FERC accounts 920 and 517). • Payroll taxes (FICA, FUTA, SUTA) • Labor and expense of the Human Resource Service Center Non-Benefit employees: • Payroll taxes (FICA, FUTA, SUTA) • Workers compensation
Provider of Service:	Service Company Operating companies or affiliates
User of Service:	Operating companies or affiliates, including utility operations, jurisdictions, and non-regulated activities within an operating company.
Method of Allocation:	Labor overheads are allocated within a legal entity by calculating a separate loading rate for each cost category identified in the “Description” section above. For each legal entity and each category, the costs are allocated based on a single-factor formula that is comprised of total estimated costs for the category divided by total estimated productive labor costs. Legal entity specific rates for each category are applied to productive labor charges as appropriate for each resource type. Labor loadings applied to labor charges follow the labor charges. For example, Service Company labor overheads follow Service Company labor and NSPM labor overheads follow NSPM labor.

AVIATION DISTRIBUTION

Description:	The Aviation Services department in the Service Company is responsible for managing and operating the two corporate leased aircraft used by the Xcel Energy. Costs include: pilot salaries including labor overheads, O&M costs, lease costs, and A&G costs associated with managing the Aviation Services department.
Provider of Service:	Service Company
User of Service:	Service Company, operating companies or affiliates, including utility operations, jurisdictions, and non-regulated activities within an operating company.
Method of Allocation:	Aviation costs are allocated using the average of the Revenue Ratio with intercompany dividends assigned to Xcel Energy Inc., Full Time Equivalent Hours Including Overtime, and the Total Assets Ratio including Xcel Energy Inc.'s per book assets. Any spousal use of the aircraft must be approved and is billed to Xcel Energy Inc.

STORES/WAREHOUSE OVERHEAD

Description:	Inventory warehousing costs, including labor, supervision, materials and supplies are allocated through pools to the business areas as an overhead on materials and supplies as materials and supplies are issued from/returned to a storeroom or warehouse.
Provider of Service:	Service Company Operating companies
User of Service:	Operating companies or affiliates, including utility operations, jurisdictions, and non-regulated activities within an operating company.
Method of Allocation:	The overhead costs for inventory items as noted above and associated adjustments are accumulated within the Supply Chain warehouse ACC's. These accumulated overhead costs are allocated to material issuances/returns from the storeroom. Costs are collected in ACC's on the Service Company and Operating Companies; then cleared using a warehouse overhead loading based on a costing sheet, cost element and AP document type criterion.

PURCHASING OVERHEAD

Description:	The Supply Chain organization in the Service Company has the responsibility for distributing the corporate purchasing and contract services costs to the functional area(s) of the operating companies or affiliates along with the cost of the materials and supplies ordered. Purchasing costs are made up of activities such as developing requisitions, contracts and purchase orders to procure materials and services and manage supplier relationships, negotiating complex procurement agreements/contracts for strategic supplier partnerships and service contracts, monitoring supplier performance, and managing purchase records, supplier qualification records and the supplier diversity program.
Provider of Service:	Service Company Operating companies
User of Service:	Service Company, operating companies and affiliates, including utility operations, jurisdictions, and non-regulated business activities within an operating company.
Method of Allocation:	Costs are collected in ACC's on the Service Company and the operating companies and cleared using an overhead loading based on costing sheet, cost element, and AP document type criterion.

FLEET DISTRIBUTION

Description:	The Fleet Services department in the Service Company is responsible for managing the fleet assets owned by the operating companies. Fleet assets are vehicle units that are organized into fleet work centers, which group together vehicles similar in nature for a specific business function within an Operating Company. . The SAP Work Manager records the utilization of our fleet assets and allocates the cost to the business areas of operating companies and affiliates for the costs of using vehicles or associated equipment using fleet activity rates based on work centers. Fleet costs included in the calculation of the monthly billing rate include: licensing taxes and fees, lease costs, material and labor costs for maintenance and repair, fuel, labor loadings, and overhead for overall management of the Fleet Services department that includes labor, facilities, insurance, utilities, computers, phones, and office supplies.
Provider of Service:	Service Company Operating companies
User of Service:	Service Company, operating companies or affiliates, including utility operations, jurisdictions and non-regulated business activities within an operating company.
Method of Allocation:	Costs are collected in ACC's on the Service Company and operating companies which are cleared using an overhead fleet rate based on the weighted vehicle type to the respective business area.

INFORMATION TECHNOLOGY

Description:	The Business Systems organization in the Service Company is responsible for managing the corporate IT assets and services of Xcel Energy. Business Systems bills out O&M and capital costs related to Xcel Energy's corporate IT equipment and services incurred internally, as well as costs incurred through third party vendors. Costs include system O&M, desktop services, phone service, servers, infrastructure costs, software, software licensing, system design and implementation, labor and labor overheads, etc.
Provider of Service:	Service Company
User of Service:	Service Company, operating companies, or affiliates, including utility operations, jurisdictions and non-regulated activities within an operating company.
Method of Allocation:	IT costs are charged through several different methods. Costs are charged directly to the operating companies, affiliates, jurisdictions or non-regulated activities on the invoice, timesheet, expense report or other source document to the company(ies) benefiting from the service whenever possible. If costs cannot be charged directly to an operating company, affiliate, jurisdiction or non-regulated activity, the costs are charged to the appropriate Service Company indirect ACC that will assign the costs using a cost causative method to the companies benefiting from the system application or service. For costs that can be identified as benefiting a particular service function, those services would be charged to a Service Company indirect ACC using the approved allocation factor for that business area.

ACCOUNTS PAYABLE

Description:	The Payment and Reporting Department (Accounts Payable), in the Service Company, processes several types of documents for payment on behalf of the operating companies and affiliates. Accounts Payable uses SAP to process invoice payments associated with purchase orders, contracts, requests for payment (non-purchase orders, non-contract invoices) and employee payments, including per diem charges, suggestion system award payments and employee expense reimbursements. The charges for goods, materials and services, which post directly to the general ledger of each operating company and affiliate, differ for each type of document.
Provider of Service:	Service Company
User of Service:	Service Company, operating companies and affiliates, including utility operations, jurisdictions, and non-regulated activities within an operating company.
Method of Allocation:	Within each operating company and affiliate, charges are directly assigned whenever possible. Charges may be distributed to multiple business functions or business areas based on the accounting code(s) on each document. If necessary, costs may be allocated using any surrogate measure that has a logical or observable correlation to the charges in the quantities sold, the services that caused the cost to be incurred or that benefited from the cost. The following are examples of some of the logical or observable correlations used to allocate costs contained on Accounts Payable documents: • Quantity (units, count, etc.) • Measurement or size (length, space, columnar inch, etc.) • Volume (barrels, gallons, liters, etc.) • Weight (ounce, pound, ton, etc.) • Hours (hours of professional or contract services) • Labor dollars (charge is in the same proportion as the labor hours of the department) • Number of customers, meters, employees, etc. • Revenue dollars • Plant in service • Square footage

SHARED ASSETS DISTRIBUTION

Description:	Shared assets are defined as capitalized assets that are owned by one legal entity but are used for the benefit of multiple entities. This would include land structures and improvements, office furniture and equipment, computer and communication equipment, and some software systems that are used by employees in the performance of their jobs.
Provider of Service:	Operating companies or affiliates
User of Service:	Service Company, operating companies and affiliates
Method of Allocation:	All allocations are billed through the Service Company and charged to a Service Company internal order that will assign the costs using a cost causative method to the companies benefiting shared assets. For IT related assets, the costs will be charged to the system application or service internal order. For facility assets, the costs will be charged to the respective Service Company facilities ACC that will assign the costs following employee labor.

FACILITIES DISTRIBUTION

Description:	Facilities costs are assigned or allocated to the functional areas of operating companies and other affiliates who benefit from the use of the facilities. Depending on whether a building is used by one utility company or is a "shared" building, i.e., building used by employees of more than one operating company or affiliate, facility costs may include: Single-utility facility: The administrative property services labor and non-labor costs, utility expenses, maintenance costs for structures and systems, pro-rated share of property taxes (for owned buildings), and the rent and occupancy expenses (for leased buildings). Shared facility: Administrative property services labor and non-labor costs, utilities expenses, and the maintenance costs for structures and systems are captured. If the building is leased, the rent is included. If the building is owned, the carrying costs of the shared assets, such as the depreciation and a return on rate base, are included in the facilities' cost. The Property Services department is responsible for the owned and leased facility.
Provider of Service:	Service Company or operating companies
User of Service:	Service Company, operating companies, and affiliates
Method of Allocation:	Costs for a single-utility facility are accumulated in the ACC of the company benefitting from the use of the building, and are then allocated to functional FERC rent accounts based on the most recent quarter's labor charges. Costs related to a shared facility, i.e., buildings used by employees of more than one operating company or affiliate, are first accumulated in ACC's specific to the shared facility and then distributed to each operating company and affiliate based upon the most recent quarter's labor for the specific employees located in each facility. Once costs are assigned to the appropriate company, they are then allocated to the functional FERC rent accounts based on the most recent quarter's labor charges.

MONEY POOL

Description:	Through the Utility Money Pool ("UMP"), temporary surplus funds of Xcel Energy are available for short-term loans to other operating companies with cash needs.
Provider of Service:	Service Company
User of Service:	PSCo, NSPM, SPS
Method of Allocation:	An operating company can borrow from, and make loans to, the UMP, which is administered at cost by the Service Company. In addition, the holding company can deposit surplus funds into the UMP, but cannot borrow from the UMP. Interest income or expense is charged or credited, as appropriate, to the UMP participants. All charges are directly billed from the Service Company to the appropriate operating company. NSPM petitioned for and received approval on the use of a UMP in Docket No. AI-04-100.

CUSTOMER BILLING

Description:	NSPM bills customers for electric, gas, propane, and miscellaneous non-regulated activities through the customer billing system.
Provider of Service:	Operating companies
User of Service:	Operating companies, including utility operations, jurisdictions, and non-regulated activities.
Method of Allocation:	Costs related to customer billing are direct charged to specific operating companies whenever possible. When costs cannot be directly assigned to a specific operating company, they are allocated based on the number of customers. Non-regulated activities that use the customer billing system are allocated a customer accounting overhead based on revenue dollars. See Section VII.

ENGINEERING AND SUPERVISION ("E&S") OVERHEAD

Description:	E&S costs are capitalized as construction overheads. E&S overheads are applied where it is not practical to direct charge the pay and expense of the engineers, surveyors, draftsmen, inspectors, first line management, and their assistants to construction. NSPM uses the E&S overhead allocation to charge these expenses to capital projects.
Provider of Service:	Operating companies and Service Company
User of Service:	Operating companies.
Method of Allocation:	Costs related to E&S are gathered in an ACC separately by functional class and utility (production, transmission, and distribution). The ACC's are fully allocated on a monthly basis to clear the balances to zero. These costs are sent to the fixed asset ledger and then are allocated to each eligible capital internal order based on current month charges and the calculated rate. The fixed asset ledger tracks all capital projects and work order expenditures for Xcel Energy on a life-to-date basis. Once expenditures are recorded on the books of the appropriate legal entity, the fixed asset ledger system generates the overhead allocations, and if appropriate, AFUDC, which are then applied to the individual internal orders. In addition, the fixed asset ledger calculates monthly depreciation by legal entity and handles the transfer of work orders from FERC account 107, Construction Work in Progress; to FERC account 106, Completed Construction-Not Unitized; to FERC account 101, Utility Plant in Service. The transfer of non-utility costs is within FERC account 121, Non-Utility Property using sub accounts.

CAPITAL A&G

Description:	A&G costs are capitalized as construction overheads. The overhead relates to all the personnel in the administrative office that work on construction to assure its continued operation, but are not direct to any one project. A prime example is the payroll analyst whose responsibility it is to assure the construction labor receives its payroll checks. Because it is inefficient for these employees to direct charge all the work orders an overhead process is used to facilitate charging the capital work orders.
Provider of Service:	Operating companies and Service Company
User of Service:	Operating companies.
Method of Allocation:	Each operating company performs an A&G study every other year to review the time employees in certain administrative departments spend on capital work. A percent of payroll for these employees, based on the A&G study results is charged to an overhead allocating cost center, one-twelfth each month. The overhead cost center is allocated to each work order based on current month charges.

VI. UTILITY ALLOCATIONS

OVERVIEW

NSPM's costs are directly assigned or allocated to electric, gas, or non-regulated activities whenever possible or charged as common and then allocated to the electric and gas utilities using utility allocations. Common utility costs are grouped into two categories: (1) O&M utility allocations and (2) rate base and non-O&M utility allocations. The O&M utility allocations are processed monthly within SAP and are explained below. The common rate base and non-O&M utility allocations are completed as part of an annual study and for rate case filing purposes which are explained below.

O&M UTILITY ALLOCATIONS

Introduction

Common O&M utility allocations are applied to common costs that are recorded in A&G (FERC accounts 920-935), customer accounting, and customer information and sales (FERC accounts 901-917). Table A in this section lists the NSPM allocation methodology applied to each FERC account or range of FERC accounts.

Methodology

NSPM uses the following methods to allocate common O&M costs. These methods were developed to achieve the most cost causative relationship that each FERC account or range of FERC accounts has with electric and gas utility operations. The allocators used are as follows:

Customer Allocator

The customer allocator is used to allocate common utility costs in FERC accounts 901-903, and the non-commodity bad debt portion of FERC 904 and 905-917 among electric and gas operations. The allocation is based on the customer bill counts for the electric and gas utilities. The allocator used in the current year is developed based on the previous years' actual customer bill count.

Revenue Allocator

The revenue allocator is used to allocate common utility costs for commodity bad debt, recorded in FERC account 904, among electric and gas operations. The allocation is based on a rolling four-year average of actual electric and gas revenues. The allocator in the current year is developed based on the four previous years' actual operating revenues from the corporate income statement.

Three-Factor Allocator

The three-factor allocator is used to allocate common utility costs in FERC account ranges 920-924 and 927-935 among electric and gas utilities. The allocation is based on the weighted average of operating revenue, plant in service, and supervised O&M. The allocator used in the current year is developed based on the previous years' actual operating revenue, plant in service and supervised O&M.

Labor Allocator

The labor allocator is used to allocate common utility costs in FERC accounts 925-926 to the electric and gas departments. The allocation is based on operating labor for the electric and gas utilities. The allocator used in the current year is developed based on the previous years' actual operating labor.

RATE BASE AND NON-O&M UTILITY ALLOCATIONS

Introduction

A study is performed annually, and also for rate case filing purposes, to identify all rate base and non-O&M costs that are common among the utility operations of NSPM in order to allocate them to the electric and gas utilities.

Methodology

NSPM uses the following methodology to allocate common rate base and non-O&M costs. These allocation factors were developed to achieve the most cost causative methodology based on the pool of costs being allocated. Table B in this section lists the methodology applied to specific pools of costs. The allocators used are as follows:

Three-Factor Allocator

The allocation is based on the weighted average of operating revenue, plant in service, and supervised O&M. The allocator used in the current year is developed based on the previous years' actual operating revenue, plant in service and supervised O&M.

Computer Software Study

A composite allocator is used to allocate common computer software rate base (plant) and non-O&M (plant related) costs among electric and gas utilities. Software assets and related costs are presented in a cost of service study using a single amount. A study of all computer software is done to determine how each individual software asset that is part of the single amount should be allocated. All individual allocations are summarized to create a single composite allocation that is then applied to the summarized computer software plant and plant related costs.

Transportation Study

Individual allocators are used to allocate common transportation rate base (plant) and non-O&M (plant related) costs among electric and gas utilities. Transportation assets are reviewed to determine where vehicles are used and allocation factors are developed.

Table A – O&M Utility Allocations

FERC Account	Allocation Method	Basis for Allocation Selection
901-917 (excluding commodity bad debt in FERC 904)	Customer Allocator	Customer bill counts are a reasonable methodology to use to allocate common customer accounting and customer information and sales costs recorded in FERC accounts 901-917 because these costs are customer related costs, e.g., credit and collection, customer accounting, bad debt, etc.
904 (commodity bad debt portion)	Revenue Allocator	A revenue allocator is a reasonable methodology to allocate commodity bad debt because these costs have a cost-causative relationship to uncollectible utility revenues.
920-924	Three-factor Allocator	A three-factor allocation is reasonable because there is no single allocator that could provide a cost-causative link. A three-factor allocator that measures three distinct aspects of the Company and results in an overall fair assignment of costs to the electric and gas utilities is used and is based on equally weighting operating revenue, plant in service and supervised O&M.
925-926	Labor Allocator	A labor allocation is reasonable because the costs recorded in these accounts are injuries and damages and pension and benefit costs. These costs have a cost-causative relationship with labor.
927-935	Three-factor Allocator	A three-factor allocation is reasonable because there is no single allocator that could provide a cost causative link. A three-factor allocator that measures three distinct aspects of the Company and results in an overall fair assignment of costs to the electric and gas utilities is used and is based on equally weighting operating revenue, plant in service and supervised O&M.

Table B – Rate Base and Non-O&M Utility Allocations

Utility	Functional Class	Pool of Costs	Allocation Methodology
Electric			Direct Assignment
Gas			Direct Assignment
Common	26/Common Intangible Plant	Computer Software	Computer Software Study
Common	31/Common General Plant	General Furniture & Equipment	Three-Factor Allocation
Common	31/Common General Plant	Electric Distribution – Mass – MN	Direct Assignment to Electric
Common	31/Common General Plant	Electric Distribution – ND	Direct Assignment to Electric
Common	31/Common General Plant	Electric Distribution – MN	Direct Assignment to Electric
Common	31/Common General Plant	Electric Distribution Vaults	Direct Assignment to Electric
Common	31/Common General Plant	Allen S King Plant	Direct Assignment to Electric
Common	31/Common General Plant	Electric Transmission Line – MN	Direct Assignment to Electric
Common	31/Common General Plant	Electric Transmission Substation – MN	Direct Assignment to Electric
Common	31/Common General Plant	Gas Distribution – MN	Direct Assignment to Gas
Common	31/Common General Plant	General Tools and Other Equipment	Three-Factor Allocation
Common	31/Common General Plant	Office, Service & Other Bldgs – MN	Three-Factor Allocation
Common	31/Common General Plant	Office, Service & Other Bldgs – ND	Three-Factor Allocation
Common	31/Common General Plant	Office, Service & Other Bldgs – SD	Three-Factor Allocation
Common	31/Common General Plant	Software – Minnesota	Three-Factor Allocation
Common	31/Common General Plant	Transportation Equipment – MN	Transportation Study
Common	31/Common General Plant	Transportation Equipment – MN	Transportation Study
Common	31/Common General Plant	Transportation Equipment – SD	Transportation Study
Common	31/Common General Plant	Prairie Island	Direct Assignment to Electric
Common	31/Common General Plant	Inver Hills – Prod Other	Direct Assignment to Electric
Common	31/Common General Plant	Big Oaks Rec Area	Three-Factor Allocation
Common	31/Common General Plant	Black Dog	Direct Assignment to Electric
Common	31/Common General Plant	High Bridge	Direct Assignment to Electric
Common	31/Common General Plant	Riverside	Direct Assignment to Electric
Common	31/Common General Plant	Sherco	Direct Assignment to Electric
Common	31/Common General Plant	Gas Prod – Wescott – MN	Direct Assignment to Gas
Common	31/Common General Plant	General Tools and Other Equipment	Three-Factor Allocation
Common	31/Common General Plant	General Plant – MN	Three-Factor Allocation
Common	31/Common General Plant	General Plant – SD	Three-Factor Allocation
Common	31/Common General Plant	General Plant – ND	Three-Factor Allocation

VII. NON-REGULATED ACTIVITY ALLOCATIONS

INTRODUCTION

The purpose of this section is to detail the methods of assigning and allocating costs between the regulated services and the non-regulated activities of NSPM.

NSPM follows the same approach for all types of costs for its fully distributed costing method. As discussed earlier in the CAAM, NSPM's method was approved by the Commission in its electric and gas rate cases (E002-GR-92-1185, G002-GR-92-1186 and G002/GR-97-1606) and the Commission's September 28, 1994 Order in Docket No. G,E-999/CI-90-1008.

The Commission established the following hierarchical cost assignment and allocation principles in Docket No. G,E-999/CI-90- 1008:

1. Tariffed rate shall be used to value tariffed services provided to non-regulated activities.
2. Costs shall be directly assigned to either regulated or non-regulated activities whenever possible.
3. Costs that cannot be directly assigned are common costs, which shall be grouped into homogenous cost categories. Each cost category shall be allocated based on direct analysis of the origin of the costs whenever possible. If direct analysis is not possible, common costs shall be allocated based upon an indirect cost causation.
4. Whenever neither direct or indirect measures of cost causation can be found, the cost category shall be allocated based upon a general allocator.

This process accomplishes the proper separation of costs between NSPM's regulated utility business and non-regulated activities. Each activity that could be considered as being outside of NSPM's electric and gas business is reviewed for regulated/non-regulated treatment. If the activity is approved to be treated as a non-regulated operation, the non-regulated cost allocation process is followed.

There are limited situations where an activity that would be in the public interest could not be pursued if a fully distributed costing approach was followed. In such circumstances, NSPM has filed, and will continue to file, any deviation from a fully distributed costing process on a project-specific basis. Any existing exceptions have been filed and approved by the Commission.

Evaluation Process

NSPM's approach to fully distributed costing includes the following steps of analysis: business profile, direct charging, labor overheads, cost causation allocation, labor related overhead, and corporate residual allocation. Non-NSPM affiliates are charged a working capital fee as discussed in Section IV.

Business Profile

The allocation process begins by reviewing each non-regulated activity for the services NSPM's utility business will be providing to the non-regulated activity.

Direct Charging (Addresses Principle #2)

Cross charges between NSPM service providers and non-regulated activities are reviewed with the business. Any process, project, or service performed for the direct benefit of a non-regulated activity is directly charged to the non-regulated activity. The business area providing service to the non-regulated activity communicates the anticipated level of service and how much the service will cost.

Labor charges are directly assigned to the non-regulated activity within the budgeting process, generally based on historical charges and taking into consideration known changes. The non-labor charges are directly charged. This process enables charging for all service that will be provided.

Cost Causation Allocations (Addresses Principle #3)

If no direct charge has been established for a service expected to be provided, a cost causation allocation is developed. Direct charging is preferred. However, if a service is expected to be provided and was not budgeted as a direct charge, an estimate of the cost of the service is made and allocated to the non-regulated business. An example of this would be, when a service is being provided, but it is at such a minimal level that it would be very difficult or cost prohibitive to charge on a direct basis.

Overhead Costs (Addresses Principle #4)

The overhead allocation factors capture indirect costs associated with providing services to non-regulated activities.

NSPM currently uses a labor overhead rate developed by reviewing the expenses incurred in support of employee related activities (such as employee programs, employee relations, training, employment, compensation and benefits program development costs, diversity, safety), office equipment needs, and supervision of the service provider. The labor overhead is applied to fully loaded labor. The labor related overhead is applied to non-regulated services wholly contained within NSPM and affiliate or third party transactions.

For non-regulated services wholly contained within NSPM, a portion of NSPM's corporation costs are allocated based on a two-factor formula that takes into consideration the relative size of the non-regulated business by using number of employees and revenues.

Working Capital Fee (Addresses Principle #3)

The working capital fee is applied to non-NSPM affiliates. The fee is based on the current Prime Rate and is reviewed and updated quarterly. This fee is to compensate the regulated business for the cost of working capital used by affiliates.

VIII. JURISDICTIONAL ALLOCATIONS

INTRODUCTION

NSPM's methods for assigning and allocating common O&M costs, plant and plant related, and other rate base investment to jurisdictions is intended to distribute costs in a manner that most closely reflects the benefit received from the expenditure. Accurately stating the assigned and allocated costs of the Company, as they relate to causation of the costs, is a fundamental part of creating a fair distribution of those costs to jurisdiction.

NSPM uses three methods to assign and allocate O&M expense, plant and plant related, and other rate base investment to jurisdiction:

1. direct assignment based on FERC account and location,
2. allocate based on cost causation, and
3. allocate based on a default allocator.

Determination of the assignment and allocation of costs to jurisdiction is an annual process designed to identify the jurisdiction(s) that receive the benefit from the cost or investment. During the review, the three methods stated above are used to ensure that the appropriate jurisdiction(s) is assigned or allocated the cost. It is NSPM's primary goal to direct assign or allocate based on cost causation as often as possible, and allocate based on a default as little as possible.

The first step in assigning costs and investments to a jurisdiction is to identify all costs that can be directly assigned to a jurisdiction (Minnesota, North Dakota or South Dakota), based on the location where work is being performed. For O&M expense, the SAP general ledger account has a location indicator (Profit Center) and a FERC account number associated with it and these are used to determine the appropriate jurisdiction(s) for assigning costs. The individual business areas determine and maintain the appropriate values for these codes based on the type of work being performed and which customers benefit from it. For plant investment data, the PowerPlan system's functional class ID, state code and the function that it is serving are used to determine the appropriate jurisdictions to assign costs for plant, plant related and other rate base costs.

Direct Assignment Based on FERC Account and Location

The first method NSPM uses is to direct assign costs whenever possible. For example, the distribution portion of an electric substation (that which is assigned to a distribution FERC account function) and is located in the Twin Cities metro area can be directly assigned to the Minnesota jurisdiction based on location as it directly serves only customers in Minnesota. In addition, all gas transmission and distribution property is directly assigned to the jurisdiction based on where the property is located as defined within the PowerPlant system. The Capital Asset Accounting organization maintains the capitalized property data.

An O&M example of direct assignment (expense) would be either electric or gas special meter reading done in the Twin Cities metro area (assigned to a distribution FERC account). The meters read are for customers in the State of Minnesota; therefore, the related costs are directly assigned to the Minnesota jurisdiction.

All regulatory expenses specific to a jurisdiction are directly assigned to that jurisdiction. For example, indirect assessments charged to NSPM, from the Minnesota Department of Commerce and the Commission, are directly assigned to the Minnesota jurisdiction.

Allocation Based on Cost Causal Relationship

The second method NSPM uses identifies all investments and costs that can be assigned to jurisdiction based on a causal relationship, and allocates these costs using the most cost causal allocation method. Examples of electric and gas analyses are as follows:

Electric

NSPM operates an integrated electric transmission system that transports electricity to NSPM's distribution system that in turn, supplies electricity to all of NSPM's customers. The transmission system is built to meet the demand created by serving its customers and, therefore, NSPM uses a coincident peak transmission demand taken from twelve consecutive months that constitute a calendar year method, to allocate transmission investment to all of its jurisdictions. All of the expense and plant investment, assigned to transmission function, exists to support NSPM's infrastructure, is fixed in nature and is assigned to jurisdiction based on transmission demand.

The cost causation allocators used for electric production expense or plant investment is a twelve-month coincident peak demand or energy, depending on the type of expense or plant investment. If the expense is variable in nature, energy is used to make the assignment to jurisdiction. If it is determined that the expense or plant investment exists to support NSPM's infrastructure and is fixed in nature, the demand allocator is used to make the assignment to jurisdiction.

Gas

From a supply standpoint, for example, NSPM operates its gas distribution system as a single unit. NSPM purchases natural gas, pipeline delivery capacity, and transmission of gas purchased to meet its customers' requirements on a system-wide basis. In addition, NSPM also operates propane-air (LPG) peak shaving facilities and liquefied natural gas (LNG) peaking facilities to meet firm demand in excess of natural gas daily pipeline entitlement for the benefit of the entire NSPM system. Because these types of costs support the entire operating company system, it is not possible to direct assign them to a specific jurisdiction. For this example, the O&M production and storage functions are allocated to jurisdiction based on the type of expense within the FERC account number. The transmission function is allocated based on the gas load dispatch allocator that is a combination of the design day firm demand allocator and total annual throughput. For plant investment, all production and storage facilities are allocated based on the gas design day allocator related to the design day firm demand.

Electric & Gas

Cost and investment in support of NSPM's distribution, customer accounting, and customer information & sales are more easily identified by state based on the location or where the work is being performed, or they can be allocated to jurisdiction using customers as a basis. In cases where services are provided and serve all regional customers, a regional allocator is developed which reflects the number of customers served in Minnesota and North Dakota or Minnesota and South Dakota, depending on the region. This represents a causal relationship between costs incurred in those regions and the assignment of costs to jurisdiction. Locating services performed in the Fargo area is an example of these types of costs. Locating services are performed for customers on both sides of the Minnesota/North Dakota border and are, therefore allocated to jurisdiction based on the number of year-end average customers in the North Dakota Region, which includes Fargo, Moorhead, Grand Forks, East Grand Forks and Minot.

Allocation Based on a Default Allocator

Allocation of common and general investment or A&G expense: costs and investment that cannot be assigned to jurisdiction using either direct assignment or allocation based on cost causation as described above are allocated to jurisdiction using a default allocator.

Common and General Plant Investment

The default allocator for electric plant investment is determined by the function that it serves. Common and general plant that serves production uses a twelve-month coincident peak demand allocator to allocate costs to jurisdiction. Plant serving transmission uses a twelve-month coincident peak transmission demand allocator to allocate costs to jurisdiction. For plant serving distribution, the number of year-end average customers is used to allocate costs to jurisdiction.

For Gas plant a default allocator is also determined by the function that it serves. For general and common plant, a year-end average customer allocator is used as the default. If the investment function has been determined to be gas production related, then the default jurisdictional allocator used in the production allocator is gas design day.

Administrative and General Expenses

When assigning or allocating A&G expenses to jurisdiction, a cost causative allocator is used if a functional relationship is easily established. In other instances, Electric A&G costs are allocated to jurisdiction using an equally weighted two-factor allocator based on electric plant in service and electric O&M expense (excluding A&G). The two factor allocator is developed by first calculating a three part historical ratio of plant investment directly serving production, transmission or distribution and a three part historical ratio of O&M expenses assigned to FERC accounts that are either production, transmission or directly serve customers (distribution, customer accounting, customer information or sales). These two ratios are then averaged to develop an equally weighted production, transmission and distribution ratio. This resulting three part ratio is then multiplied times the jurisdictional O&M default allocation ratios. The electric production portion is allocated to jurisdiction using a twelve-month coincident peak demand allocator; the transmission portion using the transmission demand allocator; and the customer portion is allocated using twelve-month end-of-year customers. The final step is to add the three sets of jurisdictional ratios together to form the two factor jurisdictional allocator used to allocate electric A&G costs supporting corporate functions.

Gas A&G expenses are allocated to jurisdiction using the appropriate customer allocation as a default allocator, based on the SAP account location indicator (profit center).

A more detailed description of each allocation type and method of allocation, including examples of why the allocation was chosen to assign costs to jurisdiction is included below.
Table C in this section lists the methodology applied to specific pools of costs.

ALLOCATION METHODS

GAS & ELECTRIC

Allocation: Direct Assigned

This allocation type is used to assign all expenses that are determined to be directly assignable to a jurisdiction (Minnesota, North Dakota, and South Dakota).

Allocation: Direct Assigned: State of Minnesota

This allocation type is used for all expenses that are determined to be for the direct benefit or in direct support of the Minnesota jurisdiction. The types of costs direct assigned include: direct and indirect assessments related to one of Minnesota's regulatory bodies, legal department expense budgeted in support of Minnesota, economic development activities in the state of Minnesota, facilities expenses in support of the distribution business unit in the state of Minnesota, delivery system operation and maintenance costs in the Twin Cities metro area, Northwest and Southeast regions and automated energy system (AES) expenses.

Allocation: Direct Assigned: State of North Dakota

This allocation type is used for all expenses that are determined to be for the direct benefit or in direct support of the state of North Dakota jurisdiction. The types of costs direct assigned include: regulatory development activities based out of the North Dakota regional offices, direct and indirect assessments related to the North Dakota regulatory bodies, legal department expenses budgeted in support of North Dakota, economic development activities performed directly for North Dakota and work performed in the Minot area for the sole benefit of North Dakota customers.

Allocation: Direct Assigned: State of South Dakota

This allocation type is used for all expenses that are determined to be for the direct benefit or in direct support of the state of South Dakota jurisdiction. The types of costs direct assigned include: direct and indirect assessments related to the South Dakota regulatory bodies, legal department expenses budgeted in support of South Dakota, economic development activities performed directly for South Dakota.

Allocation: Customers - Year-End Average - (Electric or Gas)

This allocation type is used to assign expenses where there is a cost causative relationship between the number of electric and gas utility NSP customers in a particular area and the service provided. This allocator is based on year-end average customer by utility.

Allocation: Customers Year-End Average Minnesota Co. MN/ND/SD

This allocation type is used to assign costs to all of Minnesota Company's jurisdictions (Minnesota, North Dakota, and South Dakota) when the work performed benefits all of the company's customers equally. This is the default allocator that is used for the electric and gas distribution, customer accounting, customer information, sales, and A& G FERC accounts.

This is also the gas utility A&G corporate function default allocator type.

Allocation: Customers Year End Average Minnesota/North Dakota

This allocation type is used to assign costs to both the North Dakota and Minnesota jurisdictions based on customers in the entire North Dakota region. This includes customers in Fargo, Moorhead, Grand Forks, East Grand Forks and Minot service areas. This method is the default allocator for O&M expenses associated with general ledger accounts where the SAP profit center designates support for Minnesota/North Dakota.

Allocation: Customers Year End Average Minnesota/South Dakota

This allocation type is used to assign costs to both the South Dakota and Minnesota jurisdictions based on customers in the entire South Dakota region. This method is the default allocator for O&M expenses associated with general ledger accounts where the SAP profit center designates support for Minnesota/South Dakota.

Allocation: Study Jurisdictional Budget Transmission

This allocation is used for all budgeted plant investment that is determined to be for the direct benefit or in direct support of transmission. It is a historical allocator based on the plant investment that has been direct assigned to jurisdiction based on its state location.

Allocation: Study Jurisdictional Budget Distribution

This allocation is used for all budgeted plant investment that is determined to be for the direct benefit or in direct support of Distribution. It is a historical allocator based on the plant investment that has been direct assigned to jurisdiction based on its state location.

ELECTRIC UTILITY ONLY

Allocation: Energy

Fuel and fuel-related items are assigned to jurisdiction based on the energy allocator because of the direct correlation of customer sales and the level of fuel consumed. These items include all fuel, purchased energy, interchange agreement energy, and variable production expenses.

Allocation: Demand Prod (Coincident Peak)

The 12 coincident peak (CP) demand production allocator is used to assign fixed capacity related expenses, plant, and plant related items to jurisdiction. Other expenses allocated to jurisdiction based on demand include: fixed production expenses, purchased power demand expense, interchange agreement demand charges and regulatory expenses not directly related to one of NSPM's jurisdictions. Also, any A&G costs that are directly in support of production are allocated using this method.

Allocation: Demand Tran (Coincident Peak)

The 12 CP demand transmission allocator is used to assign transmission FERC Accounts in support of NSPM's jurisdictions. Also, any A&G costs that are directly in support of transmission are allocated using this method.

Allocation: Two-Factor Allocator (A&G Only)

Expressed as an equally weighted factor based on electric plant in service and electric O&M expense (excluding A&G); the two-factor allocator is used to allocate electric A&G costs when there is not a direct or cost causative method available. Generally, all corporate electric A&G costs are allocated using this method.

GAS UTILITY ONLY

Allocation: Retail Revenues Cost of Gas Recovery - Demand, Commodity and Purchased Gas Adjustment True-up Study

Retail revenues include components for the recovery of costs associated with product and delivery of product to the service area. Such costs include capacity or entitlement costs, pipeline transportation costs, commodity costs and costs of alternative gas (LPG or LNG) supplied during times of firm peak demand. Regulations provide for the automatic adjustment of billing rates for price changes and the annual true up of the cost of gas incurred. Demand, commodity, and purchased gas adjustment are components of the retail revenues cost of gas recovery study. The portion of total NSPM cost of gas included in retail revenues that the Minnesota jurisdiction represents is also applied to total Minnesota company cost of gas expense accounts to achieve revenue neutrality for revenue requirements consideration.

Allocation: Design Demand Day

Expressed as a percentage, design demand day is the ratio of the Minnesota jurisdiction firm peak demand volume to the total NSPM firm peak demand volume that could occur on the distribution system on a day considered to be the most severe weather conditions that can be experienced.

Allocation: Load Dispatch

Expressed as a percentage, load dispatch is a combination of the Minnesota jurisdiction design demand day and the Minnesota jurisdiction total retail sales and transportation throughput each weighted equally.

Allocation: Limited Firm and Standby Services Study

Expressed as a percentage, limited firm and standby services, in revenues, is the ratio of Minnesota jurisdiction availability charges and volumetric charges to the total NSPM system; in costs, it is the ratio of Minnesota jurisdiction volumetric product costs to the total NSPM program product costs.

Table C

Allocation to Jurisdiction

Selection Criteria *							
Sub-Business Unit	**Plant Function**	**Functional Class ID / Description**	**Location**	**Functional Use**	**Utility**	**Jurisdiction**	**Allocation Methodology**
Budget							
Production	Production	1 / Electric Steam Production Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	2 /Electric Nuclear Production Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	3 / Electric Hydro Production Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	4 / Electric Other Production Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	4 / Electric Other Production Plant-Wind			Electric	MN/ND/SD/WHSL	Electric - Energy
Production	Production	22 / Nuclear Fuel			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Common & General	24 / Electric Intangible Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Common & General	26 / Common Intangible Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Common & General	29 / Electric General Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Common & General	31 / Common General Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	23 / Decommissioning	FERC MN		Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	23 / Decommissioning	Minnesota		Electric	MN	Direct Assigned - State of Minnesota
Production	Production	23 / Decommissioning	North Dakota		Electric	ND	Direct Assigned - State of North Dakota
Production	Production	23 / Decommissioning	South Dakota		Electric	SD	Direct Assigned - State of South Dakota
Production	Production	23 / Decommissioning	Wisconsin		Electric	WI	Direct Assigned - Wisconsin
Electric Transmission	Transmission	5 / Electric Transmission Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Transmission	Transmission	5 / Transmission Direct Assignment	Minnesota	DRCT	Electric	MN	Direct Assigned – State of Minnesota
Electric Distribution	Transmission	5 / Transmission Serving Distribution	Minnesota		Electric	MN	Direct Assigned - State of Minnesota
Electric Distribution	Transmission	5 / Transmission Serving Distribution	North Dakota		Electric	ND	Direct Assigned - State of North Dakota
Electric Distribution	Transmission	5 / Transmission Serving Distribution	South Dakota		Electric	SD	Direct Assigned - State of South Dakota
Production	Transmission	5 / Transmission Generation Step-up		BSLD, PEAK	Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Electric Transmission	Common & General	24 / Electric Intangible Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Transmission	Common & General	26 / Common Intangible Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)

Selection Criteria *							
Sub-Business Unit	**Plant Function**	**Functional Class ID / Description**	**Location**	**Functional Use**	**Utility**	**Jurisdiction**	**Allocation Methodology**
Budget							
Electric Transmission	Common & General	29 / Electric General Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Transmission	Common & General	31 / Common General Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Distribution	Distribution	6 / Electric Distribution Plant	Minnesota		Electric	MN	Direct Assigned - State of Minnesota
Electric Distribution	Distribution	6 / Electric Distribution Plant	North Dakota		Electric	ND	Direct Assigned - State of North Dakota
Electric Distribution	Distribution	6 / Electric Distribution Plant	South Dakota		Electric	SD	Direct Assigned - State of South Dakota
Electric Distribution	Distribution	6 / Electric Distribution Plant	Wholesale		Electric	WHSL	Direct Assigned - Wholesale Full Requirements
Production	Distribution	6 / Distribution Generation Step-up		PEAK	Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Electric Transmission	Distribution	6 / Distribution Serving Transmission		TBULK	Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Distribution	Common & General	24 / Electric Intangible Plant			Electric	MN/ND/SD/WHSL	Customer Year End Average - Electric Minnesota Company MN/ND/SD/WHSL
Electric Distribution	Common & General	26 / Common Intangible Plant			Electric	MN/ND/SD/WHSL	Customer Year End Average - Electric Minnesota Company MN/ND/SD/WHSL
Electric Distribution	Common & General	29 / Electric General Plant			Electric	MN/ND/SD/WHSL	Customer Year End Average - Electric Minnesota Company MN/ND/SD/WHSL
Electric Distribution	Common & General	31 / Common General Plant			Electric	MN/ND/SD/WHSL	Customer Year End Average - Electric Minnesota Company MN/ND/SD/WHSL
Gas	Production	7 / Gas Manufactured Production Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Storage	9 / Gas Underground Storage Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Transmission	10 / Gas Transmission Plant			Gas	MN	Direct Assigned – State Of Minnesota
Gas	Transmission	10 / Gas Transmission Plant			Gas	ND	Direct Assigned – State of North Dakota
Gas	Distribution	11 / Gas Distribution Plant			Gas	MN	Direct Assigned – State of Minnesota
Gas	Distribution	11 / Gas Distribution Plant			Gas	ND	Direct Assigned – State of North Dakota
Gas	Common & General	25 / Gas Intangible Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Common & General	26 / Common Intangible Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Common & General	30 / Gas General Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Common & General	31 / Common General Plant			Gas	MN/ND	Gas - Design Demand Day

Selection Criteria *							
Sub-Business Unit	**Plant Function**	**Functional Class ID / Description**	**Location**	**Functional Use**	**Utility**	**Jurisdiction**	**Allocation Methodology**
Budget							
Gas	Common & General	25 / Gas Intangible Plant			Gas	MN/ND	Customer Year End Average - Gas Minnesota Company MN/ND
Gas	Common & General	26 / Common Intangible Plant			Gas	MN/ND	Customer Year End Average - Gas Minnesota Company MN/ND
Gas	Common & General	30 / Gas General Plant			Gas	MN/ND	Customer Year End Average - Gas Minnesota Company MN/ND
Gas	Common & General	31 / Common General Plant			Gas	MN/ND	Customer Year End Average - Gas Minnesota Company MN/ND
Gas	Common & General	34 / Gas Other Storage Plant			Gas	MN/ND	Gas - Design Demand Day

* All items under the Selection Criteria must be met before this allocation takes place.

2020 Test Year Budget

SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent 2020
200063	110	Executive - Corporate Governance	Executive Corporate Governance includes the labor and non-labor costs for executive corporate management, long-term business strategy development and other programs that ensure the continuity and development of management. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/No. of Employees	Executive - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. No. of Employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	39.5474%
200064	115	Shareholder - Corporate Governance	Shareholder - Corporate Governance includes the labor and non-labor costs for serving as liaison between Xcel Energy BOD and the shareholders, manages employee/executive stock award matters, liaison between Xcel Energy and the proxy advisory group, monitoring stock ownership patterns, planning shareholder meetings, coordinating the transfer agent and shareholder record keeping functions. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/No. of Employees	Shareholder - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. No. of Employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	39.5474%
200065	116	Investor Relations - Corporate Governance	Investor Relations - Corporate Governance includes the labor and non-labor costs for communications to investors and the financial community, providing management with feedback from investors, assisting in the communication to investors of debt and equity securities issuances, assists in the development of presentations for Board of Directors, develops and delivers Xcel Energy's credit story to credit rating agencies, develops and presents Xcel Energy's investment story to investors, reviews all public financial documents for accuracy and completeness and distributes all financial releases. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/No. of Employees	Investor Relations - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. No. of Employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	39.5474%
200066	121	Accounting & Reporting - Corporate Governance	Accounting & Reporting - Corporate Governance includes the labor and non-labor costs associated with preparing and filing consolidated reporting and financial statements, preparing consolidated budgets, completing the consolidation process, maintaining the books and records of Xcel Energy Inc. and Service Company, composing the corporate-wide regulatory accounting policy and compliance, Sarbanes-Oxley (SOX) documentation and compliance, and Chief Financial Officer activities related to the Audit Committee. Provides financial leadership to Xcel Energy and provides policies, controls, and leadership to the Financial Operations business area. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/No. of Employees	Accounting & Reporting- Corporate Governance 'The three-factor formula reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. No. of Employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	39.5474%
200067	131	Audit Services - Corporate Governance	Audit Services corporate governance includes the labor and non-labor costs associated with the financial operations and information system audits of the holding company and service company; evaluating and improving risk management, corporate internal control guidelines and procedures; ethical conduct and the implementation of best practices, reviewing financial reporting requirements and controls under Sarbanes-Oxley legislative requirements, auditing of consolidated financial statements and activities related to the Audit Committee, performing audits and reviews for compliance with regulatory and legal requirements an contracts with vendors and other parties, providing consulting services to management for operational and process improvement reviews, assistance in internal investigations of fraud, administering the corporate compliance hotline, conflict of interest investigations, or other potential violations of the Xcel Energy Code of Conduct. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/No. of Employees	Audit Services - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. No. of Employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	39.5474%
200068	141	Finance & Treasury - Corporate Governance	Finance & Treasury - Corporate Governance includes the labor and non-labor costs related to equity and debt securities issuance, relationships with financial institutions, cash management, investing activities and monitoring the capital markets, holding company commercial paper transactions, compliance with debt covenants, corporate-wide protection of assets from catastrophic loss using risk financing mechanisms including captive risk retention and design and negotiation of insurance contracts with commercial and industry mutual underwriters (Service Company portion of Auto Liability, Cyber, and various other insurance policies), supervising the asset management firms for the Pension Fund and 401k benefits. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/No. of Employees	Finance & Treasury - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. No. of Employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	39.5474%
200069	143	Risk Management - Corporate Governance	Risk Management Corporate Governance includes the labor and non-labor costs of providing administration of the Transaction Review Committee which handles contract and deal approvals for Commercial Operations, Resource Planning and Energy Supply, provides analysis associated with key risks facing Xcel Energy Inc., negotiates and manages required security (e.g., bank letters of credit, bonds and guarantees among others); reviews and approves all documents requiring Contracts area sign-off. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/No. of Employees	Risk Management - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. No. of Employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	39.5474%

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SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent 2020
200070	161	Corporate Strategy & Business Development - Corporate Governance	Corporate Strategy & Business Development - Corporate Governance includes the labor and non-labor costs associated with providing leadership for the implementation of company-wide business strategies and plans; portfolio management including the evaluation of potential opportunities for mergers, acquisitions and divestitures; providing financial, analytical and reporting support; researching and providing business intelligence information. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/No. of Employees	'Corporate Strategy & Bus Dev - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. No. of Employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	39.5474%
200071	171	Legal - Corporate Governance	Legal services Corporate Governance includes the labor and non-labor costs for anticipating and fulfilling the legal needs of Xcel Energy, its Board of Directors, officers, legal entities, business areas and corporate operations to protect the company's assets and to minimize potential liability. Provides services related to labor and employment law pertaining to Service Company employees, litigation, contracts, rates and regulation, environmental matters and other legal matters. Supports Xcel Energy and its subsidiaries in fulfilling corporate and business area strategies ranging from maintaining/improving regulatory relationships to continued leadership on environmental issues. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/No. of Employees	Legal - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. No. of Employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	39.5474%
200072	180	Communications - Corporate Governance	Communications - Corporate Governance includes the labor and non-labor costs to assist and ensure Executive Management, Investor Relations and others communicate appropriately with shareholders, the public, and other key stakeholder audiences. Key projects include: development and production of the annual report and other communications to investors; speeches, videos, and major presentations delivered by top executives; and speeches, displays, video and presentations for the company's annual meeting of shareholders. Media Relations contributes to building Xcel Energy's reputation by developing media and public relations strategies for major company initiatives and issues; responding to news media inquiries; working pro-actively with the media to forward story ideas and information about company events, policies and actions, and providing media training for company spokespersons. Media Relations also plays a key role in crisis communications and emergency preparedness efforts. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/No. of Employees	Communications - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. No. of Employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	39.5474%
200073	189	Human Resources - Corporate Governance	Human Resources-Corporate Governance includes the labor and non-labor costs for executive officers' and Service Company employees' compensation plans, corporate HR policies, executive policy benefit plans, payroll services for Service Company and the employees' handbook. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/No. of Employees	Human Resources (HR) - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. No. of Employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	39.5474%
200074	529; 549; 551; 561	Corporate Systems	Corporate Systems includes the labor and non-labor costs for the non-critical corporate systems.	General Allocator	Assets/Revenue/No. of Employees	CFO Systems, Corporate Systems, Enterprise Continuity and SAP GL - The Business Systems expenses related to maintenance of this system that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	39.5474%
200075	114	Board of Directors - Corporate Governance	Board of Directors - Corporate Governance includes the labor and non-labor costs related to the Board of Directors (BOD). BOD costs may include Directors fees, retirement expenses and replacement fees; Board/Committee meetings and BOD related consulting. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/No. of Employees	Board of Directors - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. No. of Employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	39.5474%
200076	182	Xcel Foundation	Xcel Foundation services includes the labor and non-labor costs associated with the management and administration of the Xcel Energy Foundation.	General Allocator	Assets/Revenue/No. of Employees	Xcel Foundation services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	39.6459%
200077	184	Branding	Branding services includes the labor and non-labor costs for brand advertising and management of community affairs programs such as employee volunteerism, educational programs and community events, the company's investment in major sponsorships such as the Xcel Energy Center as well as ensuring that such sponsorships and related activities support the company's brand, mission and values.	General Allocator	Assets/Revenue/No. of Employees	Branding services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	39.6459%
200078	410	Governmental Affairs	Governmental Affairs includes the labor and non-labor costs associated with the interpretation of laws regulations and environmental policy to ensure compliance and cost effectiveness for Xcel Energy customers and stockholders Internal legislative policy development and issues management, appraise management and internal customers of political and policy trends and developments, develop and maintain relationships with regulatory officials and staff.	General Allocator	Assets/Revenue/No. of Employees	Governmental Affairs services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	39.6757%
200079	409	Federal Lobbying	Federal Lobbying services includes the labor and non-labor costs for federal and state lobbying activities and the federal Political Action Committee (PAC).	General Allocator	Assets/Revenue/No. of Employees	Federal Lobbying services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are provided to a subset of companies based on who benefits from the services. These costs are recorded in FERC 426.4.	39.6757%

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SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent 2020
200080	135	Capital Asset Accounting	Capital Asset Acctg includes the labor and non-labor costs associated with operating and non-operating company capital asset accounting, budgeting, regulatory reporting, business area support for utility areas, and operating company budgeting support.	General Allocator	Assets/Revenue/No. of Employees	Capital Asset Acctg services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.3195%
200081	120	Accounting, Reporting, & Taxes	Accounting, Reporting & Taxes services includes the labor and non-labor costs for preparation of operating and non-operating financial statements, tax returns and reporting, performing accounting for the employee benefit plans, ensuring compliance with applicable laws and regulations of the operating and non-operating companies; composing the corporate-wide regulatory accounting policy, and coordinating the budgeting process with the operating and non-operating companies.	General Allocator	Assets/Revenue/No. of Employees	Accounting Reporting & Taxes services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.4272%
200082	130	Audit Services	Audit Services includes the labor and non-labor costs for auditing operating and non-operating companies, evaluating and improving risk management, ethical conduct and the implementation of best practices for operating and non-operating companies, conducting financial operations and information system audits, performing audits and reviews for compliance with regulatory and legal requirements and contracts with vendors and other parties; establishing and reviewing internal controls for operating and non-operating companies, establishing and reviewing SOX compliance requirements/control testing and evaluating contract risks for the operating and non-operating companies.	General Allocator	Assets/Revenue/No. of Employees	Audit Services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.4272%
200083	140	Finance & Treasury	Finance & Treasury services includes the labor and non-labor costs related to equity and debt securities issuance, cash management, relationships with financial institutions, compliance with debt covenants, Service Company portion of General and Excess liability insurance, and management of the Pension Fund and 401k benefits for operating companies.	General Allocator	Assets/Revenue/No. of Employees	Finance & Treasury services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.4272%
200084	142	Risk Management	Risk Management develops and negotiates security agreements with counterparties; reviews high-risk vendor creditworthiness for the Environmental Services group; supports wind generation, solar carbon offsets, emission allowances, bundled energy and RECs, biomass and other renewable energy purchase agreements; participates in industry contracts working groups; representing Xcel Energy operating utilities; performs production cost modeling and analysis for corporate budgeting; analyzing value and risks of structured purchases and generation system modifications; performs long range system modeling to evaluate large capacity acquisition alternatives; provides central coordination of annual capital funding process for Distribution and maintains and administers the Risk Registry database, evaluates and prioritizes specific risk mitigations for distribution assets; develops strategies for distribution infrastructure including building and implementing stochastic models for asset life-cycle analysis and other ad hoc asset specific requests; creates retail and system load and energy forecasts providing regular updates to senior management and analyses of key drivers; provides data support and analyses for financial disclosures; and provides analyses and reporting of current sales and peak demand levels relative to forecasts.	General Allocator	Assets/Revenue/No. of Employees	Risk Management services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.4272%
200086	170	Legal	Legal services includes the labor and non-labor costs for operating and non-operating legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts.	General Allocator	Assets/Revenue/No. of Employees	Legal services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.4272%
200087	123	Accounting - OpCo's	Accounting - Operating Companies includes the labor and non-labor costs associated with operating company revenue accounting, budgeting, regulatory reporting, sales and use taxes, business area support for utility areas, operating company budgeting support, and capital asset accounting.	General Allocator	Assets/Revenue/No. of Employees	Accounting - Operating Companies services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.4391%
200088	127; 133	Accounting, Reporting, Tax, Audit Services - OpCo's Electric	Accounting, Reporting, Tax, Audit Services - OpCo's Elec includes the labor and non-labor costs associated specifically with operating company electric utility revenue accounting, budgeting, regulatory reporting, sales and use taxes, business area support for utility areas, operating company budgeting support, capital asset accounting auditing operating companies , evaluating and improving risk management, ethical conduct and the implementation of best practices for operating companies electric utility, conducting financial operations and information system audits, performing audits and reviews for compliance with regulatory and legal requirements and contracts with vendors and other parties; establishing and reviewing internal controls for operating companies electric utility, establishing and reviewing SOX compliance requirements/control testing and evaluating contract risks for the operating companies electric utility.	General Allocator	Assets/Revenue/No. of Employees	Accounting, Reporting and Taxes - Operating Companies Electric services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies electric utility who benefits from the services.	44.4391%
200089	132	Audit Services - OpCo's	Audit Services - OpCo's includes the labor and non-labor costs for auditing operating companies, evaluating and improving risk management, ethical conduct and the implementation of best practices for operating companies, conducting financial operations and information system audits, performing audits and reviews for compliance with regulatory and legal requirements and contracts with vendors and other parties; establishing and reviewing internal controls for operating companies, establishing and reviewing SOX compliance requirements/control testing and evaluating contract risks for the operating companies.	General Allocator	Assets/Revenue/No. of Employees	Audit Services - OpCo's services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	44.4391%
200090	146	Risk Management - OpCo's	Risk Mgmt - OpCo's includes the labor and non-labor costs of oversight and administrative of operating company risk management work, working with counterparties to establish enabling agreements with operating companies, risk management reports including all operating companies (such as CDAD - Contract Development, Approval & Delegation or TRC- Transaction Review Committee Reporting).	General Allocator	Assets/Revenue/No. of Employees	Risk Mgmt - OpCo's services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	44.4391%
200091	147	Captive Insurance - OpCo's	Captive Insurance - The Property Loss Control Engineers services includes the labor and non-labor costs for each primary Operating Company(s) (OpCo's) as well as all of Energy Supply Services. Having an expertise in an area, they lend support to each other and members of Energy Supply, and the Utilities Group, throughout the corporation. Fire Protection, Transformer Maintenance, Turbine Characteristics, Policies and Procedures are some of the areas in which expertise has been developed. This expertise is then shared on a regular basis to the benefit of all OpCo's and it is further shared at periodic Engineering meetings hosted by Hazard Insurance, which bring together Engineers from the OpCo's, the Property Loss Control Engineers and Insurance Company representatives to promote Loss Control.	General Allocator	Assets/Revenue/No. of Employees	Captive Insurance - OpCo's services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	44.4391%
200092	162	Corporate Strategy & Business Development OpCo's	Corporate Strategy & Business Development - includes the labor and non-labor costs associated with providing leadership for the implementation of company-wide business strategies and plans; portfolio management including the evaluation of potential opportunities for mergers, acquisitions and divestitures; providing financial, analytical and reporting support; researching and providing business intelligence information.	General Allocator	Assets/Revenue/No. of Employees	Corp Strategy & Bus Dev - OpCo services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	44.4391%

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SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent 2020
200093	174	Legal - OpCo's	Legal - OpCo's services includes the labor and non-labor costs for operating companies legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts.	General Allocator	Assets/Revenue/No. of Employees	Legal - OpCo's services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	44.4391%
200094	416	Supply Chain	Supply Chain includes the labor and non-labor costs for operating companies diversity program expenses as well as various dues for specific sponsored agencies (Chamber of Commerce, social service dues, etc.)	General Allocator	Assets/Revenue/No. of Employees	Supply chain services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	44.4391%
200095	430	Energy Supply Asset Management	Energy Supply Asset Management services includes the labor and non-labor costs of providing management support to the Energy Supply organization, maximizing business value of the Energy Supply information systems, developing the business plan, optimizing plant inventory, and leading the development of asset management strategy and implementation.	General Allocator	Assets/Revenue/No. of Employees	Energy Supply Asset Management services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.4391%
200096	431	Energy Markets - Business Services	Energy Markets Business Services includes the labor and non-labor costs for financial analysis, budgeting and administrative support, managerial reporting and business planning and process initiatives, independent daily forward valuation and risk measurement of commodity transactions and system fuel and purchase power requirements to meet system loads, as well as proprietary or trading transactions; creates retail system load and energy forecasts providing regular updates to senior management and analyses of key drivers, reviews and provides comments to dealmakers on non-standard agreements and associated confirmation agreements in the areas of coal supply, gas supply, wood fuel, rail, trucking, structured power purchases and nuclear/uranium concentrates and services; provides analyses for electric/gas hedge studies and sensitivities; creates load management forecast, jurisdictional peak demand forecasts, and cost of service studies for energy trading and marketing.	General Allocator	Assets/Revenue/No. of Employees	Energy Markets - Business Services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.4391%
200097	533; 535; 539; 542	Accounting and Finance Software Applications Maintenance	Includes the labor and non-labor operating costs for the application development and maintenance of the software applications used for accounting and finance business functions.	General Allocator	Assets/Revenue/No. of Employees	CBS/ALS/CFM - The Business Systems expenses related to maintenance of this system that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.4391%
200098	468	Transm Elec FERC 566	Transm Elec FERC 566 services include transmission electric labor and non-labor costs associated with accounting, budgeting, regulatory reporting, and capital asset accounting.	General Allocator	Assets/Revenue/No. of Employees	Transm Elec FERC 566 charges that can not be directly charged to a specific legal entity and are corporate in nature. The three factor formula is used because these charges are comprised of a broad spectrum of activities and no measurable method of cost causative allocation was found.	44.4391%
200099	469	Elec Dist FERC 588	Elec Dist FERC 588 services include electric distribution labor and non-labor costs associated with accounting, budgeting, regulatory reporting, and capital asset accounting.	General Allocator	Assets/Revenue/No. of Employees	Elec Dist FERC 588 charges that can not be directly charged to a specific legal entity and are corporate in nature. The three factor formula is used because these charges are comprised of a broad spectrum of activities and no measurable method of cost causative allocation was found.	44.4391%
200100	134	Audit Services - OpCo's - Gas	Audit OpCo's Gas includes the labor and non-labor costs for auditing operating companies gas utility, evaluating and improving risk management, ethical conduct and the implementation of best practices for operating companies gas utility, conducting financial operations and information system audits, performing audits and reviews for compliance with regulatory and legal requirements and contracts with vendors and other parties; establishing and reviewing internal controls for operating companies gas utility, establishing and reviewing SOX compliance requirements/control testing and evaluating contract risks for the operating companies gas utility.	General Allocator	Assets/Revenue/No. of Employees	Audit Services - OpCo's - Gas services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies gas utility who benefit from the services.	52.0411%
200101	164	Legal - OpCo's - Gas	Legal OpCo Gas NSPM, NSPW and PSCo Gas services includes the labor and non-labor costs for operating companies gas utility legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts. This is primarily used by the General Counsel area.	General Allocator	Assets/Revenue/No. of Employees	Legal - OpCo's Gas services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	52.0411%
200102	470	Gas Dist FERC 880	Gas Dist FERC 880 services include gas distribution labor and non-labor costs associated with accounting, budgeting, regulatory reporting, and capital asset accounting.	General Allocator	Assets/Revenue/No. of Employees	Gas Dist FERC 880 charges that can not be directly charged to a specific legal entity and are corporate in nature. The three factor formula is used because these charges are comprised of a broad spectrum of activities and no measurable method of cost causative allocation was found.	52.0411%
200105	125	Accounting, Reporting, Tax - NSPM & NSPW	Acctg, Rptg, Tax - MN, WI includes the labor and non-labor costs associated with NSPM & NSPW revenue accounting, budgeting, regulatory reporting, sales and use taxes, business area support for utility areas, operating company budgeting support, and capital asset accounting.	General Allocator	Assets/Revenue/No. of Employees	Acctg, Rptg, Tax - MN, WI services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to NSPM & NSPW who benefit from the services.	86.4582%
200106	126	Accounting, Reporting, Tax - NSPM & NSPW Electric	Acctg, Rptg, Tax - MN, WI Elec Electric includes the labor and non-labor costs associated specifically with NSPM & NSPW Electric utility revenue accounting, budgeting, regulatory reporting, sales and use taxes, business area support for utility areas, operating company budgeting support, and capital asset accounting.	General Allocator	Assets/Revenue/No. of Employees	Acctg, Rptg, Tax - MN, WI Elec services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to NSPM & NSPW electric utility who benefit from the services.	86.4582%
200107	172	Legal - NSPM & NSPW	Legal - OpCo's services includes the labor and non-labor costs for operating companies legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts. This is primarily used by the General Counsel area.	General Allocator	Assets/Revenue/No. of Employees	Legal - NSPM & NSPW services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to NSPM & NSPW who benefit from the services.	86.4582%
200110	510	Passport - Accounts Payable	Passport - Accounts Payable includes the labor and non-labor costs for only the Accounts Payable module within Passport. This is applicable for when work is only being done on this module. This includes application development and maintenance costs, licensing fees, server system costs and technology risk costs specific to disaster recovery of this application.	Cost Causative	AP Transactions	Passport - Accounts Payable using total AP transactions to allocate costs is reasonable because there is a direct causal relationship with the companies using the AP function of Passport.	34.6463%
200111	544	EAI (Enterprise Application Integration)	EAI (Enterprise Application Integration) includes the labor and non-labor costs associated with the management of information systems infrastructure and working with IT Project Managers to ensure that new systems are positioned to function as successfully as possible in terms of overall performance and communication with other systems.	Cost Causative	Average of a Select Set of Software Allocators	EAI (Entrprs Applic Integrate) using average of selected software systems to allocate costs is reasonable because EAI (Entrprs Applic Integrate) is primarily the server costs supporting the selected software applications and benefits the companies using the software applications.	39.6838%
200112	562	Mainframe Charges From IBM	Labor and non-labor costs related to Mainframe IBM expenses for development, maintenance, and licensing. The Mainframe is comprised of 3 applications: Time, Gas Management System, and Monitoring Device Management System applications. This is used primarily by the Business Systems Organization.	Cost Causative	Average of a Select Set of Software Allocators	Mainframe Charges From IBM expenses can not be directly charged to a specific legal entity as the system is used by multiple entities. Using an average of selected software systems to allocate costs is reasonable because Mainframe primarily supports these selected software systems.	28.1294%
200115	514	Miscellaneous Applications	Miscellaneous Applications includes the labor and non-labor costs associated with the management of information systems infrastructure and working with IT Project Managers to ensure that new systems are positioned to function as successfully as possible in terms of overall performance and communication with other systems.	Cost Causative	Average of All Software Percentages	Miscellaneous Applications using average of all software systems to allocate costs is reasonable because Miscellaneous Applications is primarily the server costs supporting the software applications and benefits the companies using the software applications.	36.3060%
200116	441	Distribution Electric FERC 580 (E&S)	Distribution Electric FERC 580 services includes the labor and non-labor costs for the engineering and supervision of the electric distribution organization.	Cost Causative	Electric Distribution Plant	Distribution Electric FERC 580 (E&S) using the electric distribution plant to allocate the costs is reasonable because there is a direct causal relationship with the operations supported by Distribution Electric.	35.7854%

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SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent 2020
200117	453	Transmission Electric FERC 586	Distribution Elec FERC 586 services include meter expenses labor and non-labor providing direction, operations, standards and processes relating to Xcel Energy operating companies i.e.: electric distribution meters standards and development, meter purchases, etc. This allocation is used when all four jurisdictions are benefiting from the services.	Cost Causative	Electric Distribution Plant	Distribution Elec FERC 586 using distribution plant to allocate meter costs is reasonable because there is a direct causal relationship with the electric distribution plant and meter operations supported by electric distribution.	35.7854%
200118	527	EMS Distribution - FERC 581	EMS provides supervisory control and data acquisition of substation devices through Remote Terminal Units (RTU's). EMS - Distribution system includes the labor and non-labor costs for application development and maintenance of the Electric Distribution Plant information operations. This is primarily used by the Business Systems organization.	Cost Causative	Electric Distribution Plant	EMS-Distribution (Energy Mgmt System-SCADA) using electric distribution to allocate costs is reasonable because there is a direct causal relationship with the operations supported by EMS-Distribution.	35.7854%
200119	506; 507; 559	Distribution Software Systems	Distribution Software Systems includes the labor and non-labor costs for the maintenance and support for electric and gas distribution to our customers.	Cost Causative	Electric Distribution Plant/ Gas Distribution Plant	GIS (Geographic Information System) using a ratio of elec dist plant/gas dist plant to allocate costs is reasonable because GIS is used to map these distributions systems.	33.4437%
200120	536	Design Tool	Design Tool includes the labor and non-labor operating costs for the application used to design distribution electric and gas service. This includes the application development and maintenance costs, and licensing fees.	Cost Causative	Electric Distribution Plant/ Gas Distribution Plant	Design Tool using electric distribution and gas distribution plant to allocate costs is reasonable because the costs are directly related to designing of Electric and Gas distribution system.	40.0805%
200121	474	Elec Dist, Gas Dist, & Gas Trans FERC 588, 880, 859	Elec Dist, Gas Dist, & Gas Trans FERC 588, 880, 859 services include gas distribution, gas transmission, and electric distribution labor and non-labor costs associated with accounting, budgeting, and regulatory reporting.	Cost Causative	Electric Distribution Plant/ Gas Transmission Plant/ Gas Distribution Plant	Elec Dist, Gas Dist, & Gas Trans FERC 588, 880, 859 charges that can not be directly charged to a specific business unit and are corporate in nature. Using a ratio of Electric Transmission & Gas Transmission/Distribution to allocate Utility Group costs is reasonable because there is a direct causal relationship with operations supported by Utilities Group.	31.8453%
200122	442	Transmission Electric FERC 560 (E&S)	Transmission Electric FERC 560 services includes the labor and non-labor costs for engineering and supervision of the electric transmission organization.	Cost Causative	Electric Transmission Plant	Transmission Electric FERC 560 (E&S) using Electric Transmission Plant to allocate costs is reasonable because there is a direct causal relationship with the operations supported by Transmission Electric.	34.3652%
200123	451	Transmission Electric FERC 561.5	Transmission Electric FERC 561.5 services include transmission reliability, planning and standards development labor and non-labor expenses for Xcel Energy Operating Companies related to transmission assets and reliability needs and transmission customers requirements and requests i.e.: developing and maintaining transmission system models, applying methodologies and tools for analysis and simulation of systems, notification of any planned transmission changes and impacts, etc. This allocation is used when all four jurisdictions are benefiting from the services and processes.	Cost Causative	Electric Transmission Plant	Transm Elec FERC 561.5 using electric transmission plant to allocate costs is reasonable because there is a direct causal relationship with the operations supported by Transmission Electric.	34.3652%
200124	526	EMS-Transmission (Energy Management System-SCADA)	EMS provides supervisory control and data acquisition of substation devices through Remote Terminal Units (RTU's). EMS -Transmission system includes the labor and non-labor costs for the application development and maintenance of the Electric Transmission Plant information operations.	Cost Causative	Electric Transmission Plant	EMS-Transmission (Energy Mgmt System-SCADA) using electric transmission to allocate costs is reasonable because there is a direct causal relationship with the operations supported by EMS-Transmission.	34.3652%
200125	449	Transmission Electric 560 NSPM & NSPW	Transm Elec 560 NSPM & NSPW services includes the labor and non-labor costs for NSPM & NSPW engineering and supervision of the electric transmission organization. This allocation is used when Northern States Power Company-Minnesota and Northern States Power Company-Wisconsin are the only jurisdictions benefiting from the services. This is primarily used by the Safety and Transmission and Substations organizations.	Cost Causative	Electric Transmission Plant	Transm Elec 560 NSPM & NSPW using electric transmission to allocate costs is reasonable because there is a direct causal relationship with the operations supported by Transmission Electric.	74.1481%
200126	423; 440; 525	Utilities Group Administrative & General (A&G) FERC 921	Utilities Group A&G (Administrative and General) FERC 921 services includes the labor and non-labor costs for utilities group leadership, management and support services for the distribution, transmission, transportation and supply chain areas.	Cost Causative	Electric Transmission Plant/ Electric Distribution Plant/ Gas Transmission Plant/Gas Distribution Plant	Customer & Field Operations Constr, Oper & Maint using delivery gross plant to allocate costs is reasonable because these costs are directly related to the electric and gas delivery systems.	32.8072%
200127	443	Distribution Gas FERC 870 (E&S)	Distribution Gas FERC 870 services includes the labor and non-labor costs for the engineering and supervision of the gas distribution organization.	Cost Causative	Gas Distribution Plant	Using Gas Distribution to allocate Distribution Gas FERC 870 costs is reasonable because there is a direct causal relationship with the operations supported by Distribution Gas.	27.2567%
200128	445	Distribution Gas FERC 880 (Misc.)	Distribution Gas FERC 880 services includes the labor and non-labor costs for the engineering and supervision of the gas distribution organization not provided for in FERC 870. This includes activities such as operating street lighting systems and research and development costs.	Cost Causative	Gas Distribution Plant	Distribution Gas FERC 880 (MISC) using Gas Distribution to allocate costs is reasonable because there is a direct causal relationship with the operations supported by Distribution Gas.	27.2567%
200129	454	Transmission Gas FERC 878	Distribution Gas FERC 878 services include meter expenses labor and non-labor providing direction, operations, standards and processes relating to Xcel Energy Operating Companies i.e.: gas distribution meters standards and development, meter purchases, etc. This allocation is used when all four jurisdictions are benefiting from the services.	Cost Causative	Gas Distribution Plant	Distribution Gas FERC 878 using gas distribution plant to allocate meter costs is reasonable because there is a direct causal relationship with the gas distribution plant and meter operations supported by gas distribution.	27.2567%
200130	444	Transmission Gas FERC 850 (E&S)	Transmission Gas FERC 850 services includes the labor and non-labor costs for the engineering and supervision of the gas transmission organization.	Cost Causative	Gas Transmission Plant	Distribution Gas FERC 870 (E&S) using gas transmission to allocate costs is reasonable because there is a direct causal relationship with the operations supported by transmission gas.	9.4946%
200131	531	Gas SCADA (Supervisory Control and Data Acquisition)	The Gas SCADA (Supervisory Control and Data Acquisition) system includes the labor and non-labor costs for the application development and maintenance of the Gas SCADA system. SCADA is a windows-based systems that give the gas system operators the ability to monitor and control Xcel Energy's natural gas systems. Control rooms and systems are located at both Rice Street (MN) and Lookout Center (CO).	Cost Causative	Gas Transmission Plant/ Gas Distribution Plant	Gas SCADA using a ratio of gas trans plant/gas dist plant to allocate costs is reasonable because the costs are directly related to the monitoring of gas distribution and transmission.	23.5865%
200132	413	Payment and Reporting	Payment & Reporting services includes the labor and non-labor costs associated with processing payments to vendors, providing audit research and reconciliation support for Accounts Payable transactions, preparing statistical and 1099 reporting, and administering the purchase card programs.	Cost Causative	Invoice Transactions	Payment and Reporting using invoice transactions to allocate costs is reasonable because the costs are directly related to the No. of invoices processed.	25.7281%
200133	128	Proprietary Trading - Back Office	Proprietary Trading - Back Office includes the labor and non-labor costs associated with the accounting support and vice president oversight of proprietary trading activities for Northern States Power Minnesota, Public Service Company of Colorado and Southwestern Public Service Company.	Cost Causative	Joint Operating Agreement	Prop Trading - Back Office uses the Joint Operating Agreement for cost allocations as it is required for the Prop Trade NSPM, PSCo & SPS services.	36.8539%
200134	144	Proprietary Trading - Front/Mid Office	Prop Trading - Frt/Mid Office includes the labor and non-labor costs associated with proprietary trading activities which are short term transactions undertaken in the wholesale electric markets where electricity is purchased for the purpose of selling it. Also included are supporting activities: evaluating the credit worthiness of counterparties, reviewing contracts to ensure that regulations are being complied with, evaluating profitability and appropriateness of trades to ensure they are in the best interest of shareholders and rate payers, and ensuring that trades identified as proprietary appropriately fall into that category.	General Allocator	Joint Operating Agreement	Prop Trading - Frt/Mid Office uses the Joint Operating Agreement for cost allocations as it is required for the Prop Trade NSPM, PSCo & SPS services.	44.1274%
200135	414	Energy Supply Business Resources	Energy Supply Business Resources services includes the labor and non-labor costs of performance analysis, specialists and analytical services provided to the operating companies' generation facilities.	Cost Causative	MWH Generation	Energy Supply Business Resources using MWH generation to allocate costs is reasonable because the costs are directly related to the support of the power plants.	36.2141%
200136	415	Energy Markets - Fuel	Energy Markets Fuel includes the labor and non-labor costs for planning and implementing power supply portfolios to provide reliable service to native load and to capitalize on market opportunities including purchasing fuel for the operating companies' electric generation system (excluding nuclear) and resource planning and acquisition including purchase power and account management.	Cost Causative	MWH Generation	Energy Markets - Fuel using MWH generation to allocate costs is reasonable because the costs are directly related to the purchase of fuel for generation.	36.2141%
200137	455	Energy Supply Miscellaneous Power Expense OpCo's	Energy Supply Miscellaneous Power Expense OpCo's services include Energy Supply operations performance services labor and non-labor costs for non-management employees with the following accountabilities: Develop / suggest / implement improvements for multiple power plants, standardize best practices and process improvements across multiple power plants, establish operations and maintenance policies and procedures for multiple power plants. This allocation is used when all four jurisdictions are benefiting from the services.	Cost Causative	MWH Generation	ES Misc Power Expense OpCo's using MWH generation to allocate costs is reasonable because the costs are directly related to the support of the power plants.	36.2140%

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SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent 2020
200138	458	Energy Supply Operations Management OpCo's	Energy Supply Operations Management OpCo's services include management of energy supply operations services labor and non-labor costs for the following accountabilities: Operate plant equipment within requirements, maintain plant equipment, manage plant personnel in accordance with labor contracts, suggest/implement plant improvements, maintain community relationships, establish operations and maintenance policies and procedures and overhaul planning and execution. This allocation is used when all four jurisdictions are benefiting from the services.	Cost Causative	MWH Generation	ES Operations Management OpCo's using MWH generation to allocate costs is reasonable because the costs are directly related to the support of the power plants.	36.2140%
200139	461	ES Engineering and Construction	ES Engineering & Construction OpCo's services which include management and performance labor and non-labor costs for the following accountabilities: Researching, reviewing, recommending and facilitating the selection of technological alternatives for improved plant and environmental performance. Manage uniform project management process (policies). Planning for Physical Plant Modifications, which includes consolidation and management of short-term and long-term plans for physical plant modifications. Develop and execute Innovative Technology Projects such as: Biomass, Solar, Wind. Implement enterprise project management (EPM) and planning tools. Establish uniform technology, design & equipment standards. This allocation is used when NSPM, NSPW, PSCo and SPS jurisdictions are benefiting from the services.	Cost Causative	MWH Generation	ES Engineering & Construction OpCo's using MWH generation to allocate costs is reasonable because the costs are directly related to the support of the power plants.	36.2140%
200143	456	ES Misc Power Expense NSPM & NSPW	ES Misc Power Expense North services include Energy Supply operations performance services labor and non-labor costs for non-management employees with the following accountabilities: Develop / suggest / implement improvements for multiple power plants, standardize best practices and process improvements across multiple power plants, establish operations and maintenance policies and procedures for multiple power plants. This allocation is used when NSPM & NSPW jurisdictions are benefiting from the services.	Cost Causative	MWH Generation	ES Misc Power Expense North using MWH generation to allocate costs is reasonable because the costs are directly related to the support of the power plants.	94.9940%
200144	459	ES Operations Management NSPM & NSPW	ES Operations Management North services include management of energy supply operations services labor and non-labor costs for the following accountabilities: Operate plant equipment within requirements, maintain plant equipment, manage plant personnel in accordance with labor contracts, suggest/implement plant improvements, maintain community relationships, establish operations and maintenance policies and procedures and overhaul planning and execution. This allocation is used when NSPM & NSPW jurisdictions are benefiting from the services.	Cost Causative	MWH Generation	ES Operations Management North using MWH generation to allocate costs is reasonable because the costs are directly related to the support of the power plants.	94.9940%
200145	462	ES Engineering and Construction NSPM & NSPW	Energy Supply Engineering and Construction services which include management and performance labor and non-labor costs for the following accountabilities: Researching, reviewing, recommending and facilitating the selection of technological alternatives for improved plant and environmental performance. Planning for Physical Plant Modifications, which includes consolidation and management of short-term and long-term plans for physical plant modifications. Develop and execute Innovative Technology Projects such as: Biomass, Solar, Wind. Establish uniform technology, design & equipment standards. This allocation is used when NSPM and NSPW jurisdictions are benefiting from the services.	Cost Causative	MWH Generation	ES Engineering & Construction North using MWH generation to allocate costs is reasonable because the costs are directly related to the support of the power plants.	94.9940%
200146	429	Energy Markets - Regulated Trading	Energy Markets Regulated Trading services includes the labor and non-labor costs of providing electric trading services to the operating companies' electric generation systems, including load management, system optimization and origination.	Cost Causative	MWH Hours Sold	Energy Markets - Regulated Trading (Gen Book) using MWH hours sold to allocate costs is reasonable because there is a direct casual relationship between trading activities and the MWH hours sold.	36.1188%
200147	554	Business Objects	Business Objects includes the labor and non-labor costs for the application that provides critical reporting from data universes.	Cost Causative	No. of Business Objects Users	Business Objects using No. of Business Object users to allocate costs is reasonable because the costs are directly related to users who are able to access the application.	57.5662%
200148	500; 524	Business Systems	Business Systems services includes the IT costs of providing assistance to computer users across the company. Specifically Computer technology risk, software maintenance on applications distributed to all users (i.e. Microsoft PC tools), governance and project management over all IT projects, fixed management fees with outside vendors, business analytics costs, corrective and preventative maintenance, security, data backup and recovery, help desk, and amortization of outside vendor fees and costs that are not specific to an application that has a specific allocator.	Cost Causative	No. of Computers	Business Systems using No. of computers to allocate costs is reasonable because there is a direct causal relationship between the No. of computers and the cost to support them.	51.5790%
200149	534	CES (Customer & Enterprise Solutions)	The CES includes the labor and non-labor costs for the leadership of the Customer & Enterprise Solutions organization and their administrative support staff.	Cost Causative	No. of Computers/ No. of Customers/ No. of Employees	CES using a ratio of No. of Computers/Customers/Employees to allocate costs is reasonable because there is a direct causal relationship with the operations supported by CES.	45.2706%
200150	520	IVR (Interactive Voice Response)	IVR includes the labor and non-labor costs for the application development and maintenance of the Interactive Voice Response system which interacts with a customer calling Xcel Energy call centers. It is intended to help service customers without invoking a call center agent. If the call needs to be handled by an agent, account information and the reason for the call is determined which helps route the call to the appropriate agent.	Cost Causative	No. of Contacts	IVR (Interactive Voice Response) using No. of contacts to allocate costs is reasonable because this system is used to take and route customer calls and benefits customers using the Call Centers.	34.3233%
200151	447	Customer Billing FERC 903	Customer Billing FERC 903 includes the labor and non-labor costs related to the delivery of billing statements, letters and notices to Xcel customers including postage and outside services costs, oversight and administration of customer billing area, research of billing exceptions, providing escalated customer service assistance with regard to billing issues resolution, and process remittances and receivables. This allocation is used when all four jurisdictions are benefiting from the services.	Cost Causative	No. of Customer Bills	Customer Billing FERC 903 using No. of customer bills to allocate costs is reasonable because the costs are directly related to customer billing activities.	39.3807%
200152	436	Customer Care FERC 902	Customer Care 902 services includes the labor and non-labor costs for meter reading of retail and wholesale customers and determining consumption for billing purposes as well as executing field collections.	Cost Causative	No. of Customers	Customer Care 902 using No. of customers to allocate costs is reasonable because the costs are directly related to customers.	35.3623%
200153	185	Customer Safety Advertising/Information Costs	Customer Safety Advertising and Information costs services includes the labor and non-labor costs associated with public safety advertising, information and education.	Cost Causative	No. of Customers	Customer Safety Advertising/Information Costs using No. of customers to allocate costs is reasonable because the costs are directly related to customers.	35.4109%
200154	403	Customer Service IT FERC 903	Customer Service Information Technology (IT) FERC 903 services includes the labor and non-labor costs for IT applications related customer billing to customers, call center support and credit and collections.	Cost Causative	No. of Customers	Customer Service IT - FERC 903 using No. of customers to allocate costs is reasonable because the costs are directly related to customers.	35.4109%
200155	435	Customer Care (CC) FERC 903	Customer Care (CC) 903 services includes the labor and non-labor costs for contact centers, remittance processing, credit and collections, customer resource management, and contact center training. This allocation is used when all four jurisdictions are benefiting from the services such as responding to residential customer inquiries regarding billings and outages, handling inbound credit calls, outbound collections calls, managing accounts receivables, training call center staffs, developing contact center call forecasts.	Cost Causative	No. of Customers	Customer Care 903 using No. of customers to allocate costs is reasonable because the costs are directly related to customers.	35.4109%
200156	437	Customer Care FERC 901	Customer Care 901 services includes the labor and non-labor costs for the leadership of the customer care organization and their administrative support staff such as consulting costs to support overall Customer Care organizational operations.	Cost Causative	No. of Customers	Customer Care 901 using No. of customers to costs is reasonable because the costs are directly related to customers.	35.4109%
200159	405	Customer Service IT FERC 903 - NSPM & NSPW	Customer Service IT FERC 903 - North services includes the labor and non-labor costs for IT applications related customer billing to customers, call center support and credit and collections. This allocation is used when Northern States Power Company-Min	Cost Causative	No. of Customers	Customer Service IT FERC 903 - North using No. of customers to allocate costs is reasonable because the costs are directly related to customers.	84.2065%

Service Company Allocation Descriptions, Methods and NSPM Percentages - Using Headcount

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SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent 2020
200160	439	Customer Care FERC 903 - NSPM & NSPW	Customer Care 903 - North services includes the labor and non-labor costs for contact centers, and credit and collections, such as responding to commercial customers inquiries at the Business Solution Center in the North. This allocation is used when Northern States Power Company-Minnesota and Northern States Power Company-Wisconsin are the only jurisdictions benefiting from the services. This is primarily used by the Customer Care organization.	Cost Causative	No. of Customers	Customer Care North 903 using No. of customers to allocate costs is reasonable because the costs are directly related to customers.	84.2065%
200161	446	Customer Care Low Income Assistance FERC 908	Customer Care Low Income Assistance (908) services includes the labor and non-labor costs associated with the low income energy customer program such as answering calls from customers for referral to low income assistance agencies, providing information to the agencies in order to process applications for assistance, take pledges/commitments from agencies and process payments from agencies.	Cost Causative	No. of Residential Customers	Customer Care Low Income Assistance 908 using No. of residential customers to allocate costs is reasonable because the costs are directly related to customers.	41.1511%
200162	519	CL/QM (Call Logging and Quality Management)	CL/QM includes the labor and non-labor operating costs for the application development and maintenance of the Call Logging and Quality Management system which is used to monitor and record calls for contact center training and leadership teams.	Cost Causative	No. of Customers/ No. of Contacts	CL/QM (Call Logging and Quality Management) using a ratio of no. of customers/no. of contacts to allocated costs is reasonable because the system benefits current and potential customers using the Call Centers.	34.8671%
200163	181	Employee Communications	Employee Communications includes the labor and non-labor costs for the development and enhancement of employee awareness and understanding of the company's strategies, priorities, decisions and performance objectives. It develops and produces regular communication vehicles, including TODAY (daily news bulleting on intranet); XTRA (monthly print publication for all employees and retirees); All Managers E-mail (real-time communication for employees who supervise and manage others); Focus on Financials for all employees; targeted communications for specific business areas, such as Human Resources, and employee meetings.	Cost Causative	No. of Employees	Employee Communications using No. of Employees to allocate costs is reasonable because the costs are directly related to employees.	48.7360%
200164	198	Payroll	Payroll services include the labor and non-labor costs for processing payroll including consolidation of time collection, calculation of salaries and wages, administration of employee deductions, account distribution and reconciliation, allocation and accounting for employment taxes and compliance reports.	Cost Causative	No. of Employees	Payroll using No. of Employees to allocate costs is reasonable because the costs are directly related to employees.	48.7360%
200165	515; 521; 552	Employee Management Systems	Employee Management Systems includes the labor and non-labor costs for the Security Operations Center (SOC), Time capture and processing for payroll and accounting and Human Resources software. These applications and services provide services for the whole company related to enterprise security, including physical access, security monitoring and investigations, payroll and time accounting and employee information databases.	Cost Causative	No. of Employees	PeopleSoft using No. of Employees to allocate costs is reasonable because the costs are directly related to employees.	48.7360%
200166	190; 197; 199	Human Resources (Diversity/Safety/Employee Relations)	Human Resources-Diversity/Safety/Employee Relations includes the labor and non-labor costs for work performed for operating and affiliate company employees, such as diversity programs, providing workforce relations resources for labor agreements, arbitration, and training. Manage, design, and implement Corporate Safety initiatives. Staffing administration for non-bargaining positions and provides Affirmative Action plans (development) and government audit management (compliance).	Cost Causative	No. of Employees	Human Resources (Diversity/Safety/Emp Relations) using No. of Employees to allocate HR costs is reasonable because the costs are directly related to employees.	48.8220%
200167	508; 550	e-Business	The e-Business system includes the labor and non-labor costs associated with the corporate electronic business infrastructure.	Cost Causative	No. of Employees	E-Business using No. of Employees to allocate costs is reasonable because the costs benefit employees.	48.8220%
200168	517	GMS (Gas Management System)	GMS supports Xcel Energy Gas Transportation business including contracts, nominations/allocations, end-user measurement, imbalance management, and input for billing. also supports gas system supply, other balancing services. Costs include labor and non-labor for the application development and maintenance of the Gas Management System.	Cost Causative	No. of Gas Customers	GMS (Gas Management System) using No. of gas customers to allocate costs is reasonable because this system benefits gas customers.	0.0017%
200169	504; 537; 553	Energy Supply Systems	Energy Supply Systems includes the labor and non-labor costs for the non-critical applications that support the Energy Supply area. Such as Emissions Tracker, Labworks, SAP WAM, Documentum and Meridian.	Cost Causative	No. of Maximo Users	Maximo using the no. of Maximo users to allocate the costs is reasonable because there is a direct causal relationship with the operations supported by Maximo.	37.2829%
200170	518; 540	Meter Reading and Monitoring Systems	Includes the labor and non-labor operating costs for the application development and maintenance of the software applications needed to read and monitor gas and electric meters.	Cost Causative	No. of Meters	MDMS (Monitoring Device Management System) using No. of meters to allocate costs is reasonable because there is a direct causal relationship with the companies using MDMS to monitor meters.	35.6505%
200171	503; 555	CRS (Customer Resource System)	The CRS system includes the labor and non-labor costs for the CRS system, specifically, application development and maintenance costs, licensing fees, server system costs and technology risk costs specific to disaster recovery of this application. CRS is Xcel Energy's customer service and billing system.	Cost Causative	No. of Meters/ No. of Contacts	CRS (Customer Resource System) using a ratio of no. of meters/no. of contacts to allocate costs is reasonable because there is a direct causal relationship with the operations supported by CRS.	34.9869%
200172	523	Network	Network services include the labor and non-labor costs for the operation, maintenance, and management of Xcel Energy's internal and external Information Technology Network. This includes circuits, firewalls and communication assets.	Cost Causative	Phones/ Radios/ Computers	Network using a ratio of phones/radios/computers to allocate costs is reasonable because the network supports these major items.	51.0395%
200173	129	Generation/Proprietary Trading - Back Office	Generation/Proprietary Trading - Back Office includes the labor and non-labor costs associated with oversight and administration of accounting related trading costs including proprietary and generation trading for Northern States Power Minnesota, Northern States Power Wisconsin, Public Service Company of Colorado and Southwestern Public Service Company.	Cost Causative	Based on labor hour allocation by Commercial Operations front office trading activities, generation (purchase and sales) and proprietary, with the proprietary allocation to NSPM, PSCo & SPS. Proprietary trading dollars are allocated based on the Joint Operating Agreement.	Gen/Prop Trading - Back Office uses a labor hour allocation based on Commercial Operations front office Generation (purchase and sales) and proprietary trading activities is reasonable because there is a direct correlation between the front office activities and the mid-office and back-office activities. It is required to use the Joint Operating Agreement for the Proprietary split for these accounting and trading costs.	37.4489%
200174	145	Generation/Proprietary Trading - Mid Office	Generation/Proprietary Trading - Mid Office includes the labor and non-labor costs associated with independent evaluation and risk measurement of trading and generation book transactions, including preparing daily P&L (profit and loss) reports and individual trader profit and loss reports for the prop book, daily generation book valuation reports for each system showing all net fuel positions and any forward sales values and/or hedges, ensuring that margin reporting follows all SEC rules and GAAP reporting and that credit and risk policies and procedures are complied with.	Cost Causative	Based on labor hour allocation by Commercial Operations front office trading activities, generation (purchase and sales) and proprietary, with the proprietary allocation to NSPM, PSCo & SPS. Proprietary trading dollars are allocated based on the Joint Operating Agreement.	Gen/Prop Trading - Mid Office uses a labor hour allocation based on Commercial Operations front office Generation (purchase and sales) and proprietary trading activities is reasonable because there is a direct correlation between the front office activities and the mid-office and back-office activities. It is required to use the Joint Operating Agreement for the Proprietary split for these accounting and trading costs.	41.8725%
200175	513	Passport - Purchasing	Passport - Purchasing includes the labor and non-labor costs associated with the Purchasing module within Passport. This includes application development and maintenance costs, licensing fees, server system costs and technology risk costs specific to disaster recovery of this application.	Cost Causative	Purchasing Transactions	Passport - Purchasing using purchasing transactions to allocate costs is reasonable because there is a direct causal relationship with the companies using the purchasing functions of Passport.	27.7612%
200176	412	Marketing & Sales	Marketing & Sales services includes the labor and non-labor costs for marketing and sales services for the operating companies for their customers including strategic planning, segment identification, business analysis, sales planning, customer service, promoting products to the business market, and providing regulatory and policy support with respect to utility Energy Efficiency and Demand Response program design, evaluation, measurement and verification, cost effectiveness testing , and cost recovery.	Cost Causative	Revenue	Marketing & Sales using Revenue to allocate costs is reasonable because Marketing & Sales support the revenue-producing operations of the company.	41.2063%

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SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent 2020
200177	418	Rates & Regulation - Electric	Rates & Regulation - Electric includes the labor and non-labor costs for determining the regulated utilities' electric utility revenue requirements and rates for electric customers regulatory strategy, coordinating the regulatory compliance requirements, establishing and maintaining relationships with regulatory bodies, policy development of regulatory and legislative strategy, preparing and organizing rate case filings.	Cost Causative	Revenue	Rates Electric using revenue to allocate costs is reasonable because they are responsible for setting revenue requirements.	27.2928%
200178	417	Rates & Regulation	Rates & Regulation includes the labor and non-labor costs for determining the regulated utilities' revenue requirements and rates for electric and gas customers regulatory strategy, coordinating the regulatory compliance requirements, establishing and maintaining relationships with regulatory bodies, policy development of regulatory and legislative strategy, preparing and organizing rate case filings.	Cost Causative	Revenue	Rates & Regulation using revenue to allocate costs is reasonable because they are responsible for setting revenue requirements.	27.2928%
200179	509	Passport - All Modules	Passport - All Modules includes the labor and non-labor costs for accounts payable, inventory, work management and purchasing. This includes application development and maintenance costs, licensing fees, server system costs and technology risk costs specific to disaster recovery of this application.	Cost Causative	Total AP/ Inventory/ Work Management Purchase Transactions	Passport - All Modules using the total AP/inventory/WM/purch transactions to allocate the Passport costs is reasonable because there is a direct causal relationship with the companies who benefit from Passport.	34.6297%
200180	528	EMS-Shared (Energy Management System-SCADA)	EMS provides supervisory control and data acquisition of substation devices through Remote Terminal Units (RTU's). EMS-Shared system includes the labor and non-labor costs for the application development and maintenance of the Electric Transmission, Distribution and Production Plant information operations.	Cost Causative	Electric Production Plant/ Electric Transmission Plant/ Electric Distribution Plant	EMS-Shared (Energy Mgmt System-SCADA) using a ratio of electric transmission\distribution\production to allocate costs is reasonable because there is a direct causal relationship with the operations supported by EMS-Shared.	41.8440%
200181	464	Energy Supply Environmental Policy & Services OpCo's	Energy Supply Environmental Policy & Services OpCo's services include the labor and non-labor costs dedicated to air quality, renewable energy, innovative technology and climate change, develop corporate compliance strategy, regulatory agency interaction (both at the federal and/or state level), permitting and compliance reporting, waste management, combustion byproducts management, environmental compliance auditing, provide support to the Environmental Council and assist with environmental communications strategies. This allocation is used when NSPM, NSPW, PSCo and SPS jurisdictions are benefiting from the services.	Cost Causative	Electric Production Plant/ Electric Transmission Plant/ Electric Distribution Plant/ Gas Transmission Plant/ Gas Distribution Plant	ES Environmental Policy & Services OpCo's using gross plant assets to allocate costs is reasonable because the costs are directly related to the environmental policies and services which are generated by the operation and ownership of the assets.	39.6593%
200182	465	Energy Supply Environmental Policy & Services - NSPM & NSPW	ES Environmental Policy & Services North functions which include the labor and non-labor costs dedicated to air quality, renewable energy, innovative technology and climate change, develop corporate compliance strategy, regulatory agency interaction (both at the federal and/or state level), permitting and compliance reporting, waste management, combustion byproducts management, environmental compliance auditing, provide support to the Environmental Council and assist with environmental communications strategies. This allocation is used when NSPM and NSPW jurisdictions are benefiting from the services.	Cost Causative	Electric Production Plant/ Electric Transmission Plant/ Electric Distribution Plant/ Gas Transmission Plant/ Gas Distribution Plant	ES Environmental Policy & Services North using gross plant assets to allocate costs is reasonable because the costs are directly related to the environmental policies and services which are generated by the operation and ownership of the assets.	85.7587%
200184	516	PowerPlan	PowerPlan includes the labor and non-labor operating costs for PowerPlan, which is the capital asset business system which includes the following modules. Fixed Assets, Power Tax, Property Tax, Projects, Budgets, Cost Repository, Depreciation studies and Depreciation forecast. This includes the application development and maintenance costs, licensing fees, server system costs and technology risk costs specific to disaster recovery of this application.	Cost Causative	Total Plant	PowerPlan using total plant to allocate costs is reasonable because there is a direct causal relationship with the companies using PowerPlan to manage plant assets.	42.4820%
200185	512	Passport - Work Management	Passport - Work Management includes the labor and non-labor costs associated with the Work Management module within Passport. This includes application development and maintenance costs, licensing fees, server system costs and technology risk costs specific to disaster recovery of this application.	Cost Causative	Work Management Transactions	Passport - Work Management using work management transactions to allocate costs is reasonable because there is a direct causal relationship with the companies using the work management functions of Passport.	50.4073%
200805	163	Legal - OpCo's - Electric	LEGAL OpCo Electric services includes the labor and non-labor costs for operating companies electric utility legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts. This is primarily used by the General Counsel area.	General Allocator	Assets/Revenue/No. of Employees	LEGAL OpCo Electric services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies electric utility who benefit from the services.	44.4391%
200806	173	Legal - NSPM & NSPW Electric	Legal - NSPM & NSPW Electric services includes the labor and non-labor costs for NSPM & NSPW operating companies electric legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts. This is primarily used by the General Counsel area.	General Allocator	Assets/Revenue/No. of Employees	Legal - NSPM & NSPW services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to NSPM & NSPW electric utility who benefit from the services.	86.4582%

Service Company Allocation Descriptions, Methods and NSPM Percentages - Using Allocated FTE Hours as Ordered in Docket No. E,G001/AI10-690

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SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent 2020
200063	110	Executive - Corporate Governance	Executive Corporate Governance includes the labor and non-labor costs for executive corporate management, long-term business strategy development and other programs that ensure the continuity and development of management. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/FTE Hours	Executive - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. FTE Hours is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	38.5025%
200064	115	Shareholder - Corporate Governance	Shareholder - Corporate Governance includes the labor and non-labor costs for serving as liaison between Xcel Energy BOD and the shareholders, manages employee/executive stock award matters, liaison between Xcel Energy and the proxy advisory group, monitoring stock ownership patterns, planning shareholder meetings, coordinating the transfer agent and shareholder record keeping functions. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/FTE Hours	Shareholder - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. FTE Hours is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	38.5025%
200065	116	Investor Relations - Corporate Governance	Investor Relations - Corporate Governance includes the labor and non-labor costs for communications to investors and the financial community, providing management with feedback from investors, assisting in the communication to investors of debt and equity securities issuances, assists in the development of presentations for Board of Directors, develops and delivers Xcel Energy's credit story to credit rating agencies, develops and presents Xcel Energy's investment story to investors, reviews all public financial documents for accuracy and completeness and distributes all financial releases. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/FTE Hours	Investor Relations - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. FTE Hours is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	38.5025%
200066	121	Accounting & Reporting - Corporate Governance	Accounting & Reporting - Corporate Governance includes the labor and non-labor costs associated with preparing and filing consolidated reporting and financial statements, preparing consolidated budgets, completing the consolidation process, maintaining the books and records of Xcel Energy Inc. and Service Company, composing the corporate-wide regulatory accounting policy and compliance, Sarbanes-Oxley (SOX) documentation and compliance, and Chief Financial Officer activities related to the Audit Committee. Provides financial leadership to Xcel Energy and provides policies, controls, and leadership to the Financial Operations business area. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/FTE Hours	Accounting & Reporting- Corporate Governance 'The three-factor formula reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. FTE Hours is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	38.5025%
200067	131	Audit Services - Corporate Governance	Audit Services corporate governance includes the labor and non-labor costs associated with the financial operations and information system audits of the holding company and service company; evaluating and improving risk management, corporate internal control guidelines and procedures; ethical conduct and the implementation of best practices, reviewing financial reporting requirements and controls under Sarbanes-Oxley legislative requirements, auditing of consolidated financial statements and activities related to the Audit Committee, performing audits and reviews for compliance with regulatory and legal requirements an contracts with vendors and other parties, providing consulting services to management for operational and process improvement reviews, assistance in internal investigations of fraud, administering the corporate compliance hotline, conflict of interest investigations, or other potential violations of the Xcel Energy Code of Conduct. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/FTE Hours	Audit Services - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. FTE Hours is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	38.5025%
200068	141	Finance & Treasury - Corporate Governance	Finance & Treasury - Corporate Governance includes the labor and non-labor costs related to equity and debt securities issuance, relationships with financial institutions, cash management, investing activities and monitoring the capital markets, holding company commercial paper transactions, compliance with debt covenants, corporate-wide protection of assets from catastrophic loss using risk financing mechanisms including captive risk retention and design and negotiation of insurance contracts with commercial and industry mutual underwriters (Service Company portion of Auto Liability, Cyber, and various other insurance policies), supervising the asset management firms for the Pension Fund and 401k benefits. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/FTE Hours	Finance & Treasury - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. FTE Hours is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	38.5025%
200069	143	Risk Management - Corporate Governance	Risk Management Corporate Governance includes the labor and non-labor costs of providing administration of the Transaction Review Committee which handles contract and deal approvals for Commercial Operations, Resource Planning and Energy Supply, provides analysis associated with key risks facing Xcel Energy Inc., negotiates and manages required security (e.g., bank letters of credit, bonds and guarantees among others); reviews and approves all documents requiring Contracts area sign-off. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/FTE Hours	Risk Management - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. FTE Hours is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	38.5025%

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SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent 2020
200070	161	Corporate Strategy & Business Development - Corporate Governance	Corporate Strategy & Business Development - Corporate Governance includes the labor and non-labor costs associated with providing leadership for the implementation of company-wide business strategies and plans; portfolio management including the evaluation of potential opportunities for mergers, acquisitions and divestitures; providing financial, analytical and reporting support; researching and providing business intelligence information. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/FTE Hours	'Corporate Strategy & Bus Dev - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. FTE Hours is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	38.5025%
200071	171	Legal - Corporate Governance	Legal services Corporate Governance includes the labor and non-labor costs for anticipating and fulfilling the legal needs of Xcel Energy, its Board of Directors, officers, legal entities, business areas and corporate operations to protect the company's assets and to minimize potential liability. Provides services related to labor and employment law pertaining to Service Company employees, litigation, contracts, rates and regulation, environmental matters and other legal matters. Supports Xcel Energy and its subsidiaries in fulfilling corporate and business area strategies ranging from maintaining/improving regulatory relationships to continued leadership on environmental issues. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/FTE Hours	Legal - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. FTE Hours is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	38.5025%
200072	180	Communications - Corporate Governance	Communications - Corporate Governance includes the labor and non-labor costs to assist and ensure Executive Management, Investor Relations and others communicate appropriately with shareholders, the public, and other key stakeholder audiences. Key projects include: development and production of the annual report and other communications to investors; speeches, videos, and major presentations delivered by top executives; and speeches, displays, video and presentations for the company's annual meeting of shareholders. Media Relations contributes to building Xcel Energy's reputation by developing media and public relations strategies for major company initiatives and issues; responding to news media inquiries; working pro-actively with the media to forward story ideas and information about company events, policies and actions, and providing media training for company spokespersons. Media Relations also plays a key role in crisis communications and emergency preparedness efforts. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/FTE Hours	Communications - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. FTE Hours is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	38.5025%
200073	189	Human Resources - Corporate Governance	Human Resources-Corporate Governance includes the labor and non-labor costs for executive officers' and Service Company employees' compensation plans, corporate HR policies, executive policy benefit plans, payroll services for Service Company and the employees' handbook. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/FTE Hours	Human Resources (HR) - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. FTE Hours is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	38.5025%
200074	529; 549; 551; 561	Corporate Systems	Corporate Systems includes the labor and non-labor costs for the non-critical corporate systems.	General Allocator	Assets/Revenue/FTE Hours	CFO Systems, Corporate Systems, Enterprise Continuity and SAP GL - The Business Systems expenses related to maintenance of this system that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	38.5025%
200075	114	Board of Directors - Corporate Governance	Board of Directors - Corporate Governance includes the labor and non-labor costs related to the Board of Directors (BOD). BOD costs may include Directors fees, retirement expenses and replacement fees; Board/Committee meetings and BOD related consulting. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/FTE Hours	Board of Directors - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. FTE Hours is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	38.5025%
200076	182	Xcel Foundation	Xcel Foundation services includes the labor and non-labor costs associated with the management and administration of the Xcel Energy Foundation.	General Allocator	Assets/Revenue/FTE Hours	Xcel Foundation services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	38.6056%
200077	184	Branding	Branding services includes the labor and non-labor costs for brand advertising and management of community affairs programs such as employee volunteerism, educational programs and community events, the company's investment in major sponsorships such as the Xcel Energy Center as well as ensuring that such sponsorships and related activities support the company's brand, mission and values.	General Allocator	Assets/Revenue/FTE Hours	Branding services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	38.6055%

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200078	410	Governmental Affairs	Governmental Affairs includes the labor and non-labor costs associated with the interpretation of laws regulations and environmental policy to ensure compliance and cost effectiveness for Xcel Energy customers and stockholders Internal legislative policy development and issues management, appraise management and internal customers of political and policy trends and developments, develop and maintain relationships with regulatory officials and staff.	General Allocator	Assets/Revenue/FTE Hours	Governmental Affairs services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	38.6356%
200079	409	Federal Lobbying	Federal Lobbying services includes the labor and non-labor costs for federal and state lobbying activities and the federal Political Action Committee (PAC).	General Allocator	Assets/Revenue/FTE Hours	Federal Lobbying services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are provided to a subset of companies based on who benefits from the services. These costs are recorded in FERC 426.4.	38.6356%
200080	135	Capital Asset Accounting	Capital Asset Acctg includes the labor and non-labor costs associated with operating and non-operating company capital asset accounting, budgeting, regulatory reporting, business area support for utility areas, and operating company budgeting support.	General Allocator	Assets/Revenue/FTE Hours	Capital Asset Acctg services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	43.2479%
200081	120	Accounting, Reporting, & Taxes	Accounting, Reporting & Taxes services includes the labor and non-labor costs for preparation of operating and non-operating financial statements, tax returns and reporting, performing accounting for the employee benefit plans, ensuring compliance with applicable laws and regulations of the operating and non-operating companies; composing the corporate-wide regulatory accounting policy, and coordinating the budgeting process with the operating and non-operating companies.	General Allocator	Assets/Revenue/FTE Hours	Accounting Reporting & Taxes services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	43.3596%
200082	130	Audit Services	Audit Services includes the labor and non-labor costs for auditing operating and non-operating companies, evaluating and improving risk management, ethical conduct and the implementation of best practices for operating and non-operating companies, conducting financial operations and information system audits, performing audits and reviews for compliance with regulatory and legal requirements and contracts with vendors and other parties; establishing and reviewing internal controls for operating and non-operating companies, establishing and reviewing SOX compliance requirements/control testing and evaluating contract risks for the operating and non-operating companies.	General Allocator	Assets/Revenue/FTE Hours	Audit Services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	43.3596%
200083	140	Finance & Treasury	Finance & Treasury services includes the labor and non-labor costs related to equity and debt securities issuance, cash management, relationships with financial institutions, compliance with debt covenants, Service Company portion of General and Excess liability insurance, and management of the Pension Fund and 401k benefits for operating companies.	General Allocator	Assets/Revenue/FTE Hours	Finance & Treasury services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	43.3596%
200084	142	Risk Management	Risk Management develops and negotiates security agreements with counterparties; reviews high-risk vendor creditworthiness for the Environmental Services group; supports wind generation, solar carbon offsets, emission allowances, bundled energy and RECs, biomass and other renewable energy purchase agreements; participates in industry contracts working groups; representing Xcel Energy operating utilities; performs production cost modeling and analysis for corporate budgeting; analyzing value and risks of structured purchases and generation system modifications; performs long range system modeling to evaluate large capacity acquisition alternatives; provides central coordination of annual capital funding process for Distribution and maintains and administers the Risk Registry database, evaluates and prioritizes specific risk mitigations for distribution assets; develops strategies for distribution infrastructure including building and implementing stochastic models for asset life-cycle analysis and other ad hoc asset specific requests; creates retail and system load and energy forecasts providing regular updates to senior management and analyses of key drivers; provides data support and analyses for financial disclosures; and provides analyses and reporting of current sales and peak demand levels relative to forecasts.	General Allocator	Assets/Revenue/FTE Hours	Risk Management services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	43.3596%
200086	170	Legal	Legal services includes the labor and non-labor costs for operating and non-operating legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts.	General Allocator	Assets/Revenue/FTE Hours	Legal services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	43.3596%
200087	123	Accounting - OpCo's	Accounting - Operating Companies includes the labor and non-labor costs associated with operating company revenue accounting, budgeting, regulatory reporting, sales and use taxes, business area support for utility areas, operating company budgeting support, and capital asset accounting.	General Allocator	Assets/Revenue/FTE Hours	Accounting - Operating Companies services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	43.3716%
200088	127; 133	Accounting, Reporting, Tax, Audit Services - OpCo's Electric	Accounting, Reporting, Tax, Audit Services - OpCo's Elec includes the labor and non-labor costs associated specifically with operating company electric utility revenue accounting, budgeting, regulatory reporting, sales and use taxes, business area support for utility areas, operating company budgeting support, capital asset accounting auditing operating companies , evaluating and improving risk management, ethical conduct and the implementation of best practices for operating companies electric utility, conducting financial operations and information system audits, performing audits and reviews for compliance with regulatory and legal requirements and contracts with vendors and other parties; establishing and reviewing internal controls for operating companies electric utility, establishing and reviewing SOX compliance requirements/control testing and evaluating contract risks for the operating companies electric utility.	General Allocator	Assets/Revenue/FTE Hours	Accounting, Reporting and Taxes - Operating Companies Electric services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies electric utility who benefits from the services.	43.3716%
200089	132	Audit Services - OpCo's	Audit Services - OpCo's includes the labor and non-labor costs for auditing operating companies, evaluating and improving risk management, ethical conduct and the implementation of best practices for operating companies, conducting financial operations and information system audits, performing audits and reviews for compliance with regulatory and legal requirements and contracts with vendors and other parties; establishing and reviewing internal controls for operating companies, establishing and reviewing SOX compliance requirements/control testing and evaluating contract risks for the operating companies.	General Allocator	Assets/Revenue/FTE Hours	Audit Services - OpCo's services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	43.3716%
200090	146	Risk Management - OpCo's	Risk Mgmt - OpCo's includes the labor and non-labor costs of oversight and administrative of operating company risk management work, working with counterparties to establish enabling agreements with operating companies, risk management reports including all operating companies (such as CDAD - Contract Development, Approval & Delegation or TRC- Transaction Review Committee Reporting).	General Allocator	Assets/Revenue/FTE Hours	Risk Mgmt - OpCo's services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	43.3716%

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SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent 2020
200091	147	Captive Insurance - OpCo's	Captive Insurance - The Property Loss Control Engineers services includes the labor and non-labor costs for each primary Operating Company(s) (OpCo's) as well as all of Energy Supply Services. Having an expertise in an area, they lend support to each other and members of Energy Supply, and the Utilities Group, throughout the corporation. Fire Protection, Transformer Maintenance, Turbine Characteristics, Policies and Procedures are some of the areas in which expertise has been developed. This expertise is then shared on a regular basis to the benefit of all OpCo's and it is further shared at periodic Engineering meetings hosted by Hazard Insurance, which bring together Engineers from the OpCo's, the Property Loss Control Engineers and Insurance Company representatives to promote Loss Control.	General Allocator	Assets/Revenue/FTE Hours	Captive Insurance - OpCo's services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	43.3716%
200092	162	Corporate Strategy & Business Development OpCo's	Corporate Strategy & Business Development - includes the labor and non-labor costs associated with providing leadership for the implementation of company-wide business strategies and plans; portfolio management including the evaluation of potential opportunities for mergers, acquisitions and divestitures; providing financial, analytical and reporting support; researching and providing business intelligence information.	General Allocator	Assets/Revenue/FTE Hours	Corp Strategy & Bus Dev - OpCo services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	43.3716%
200093	174	Legal - OpCo's	Legal - OpCo's services includes the labor and non-labor costs for operating companies legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts.	General Allocator	Assets/Revenue/FTE Hours	Legal - OpCo's services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	43.3716%
200094	416	Supply Chain	Supply Chain includes the labor and non-labor costs for operating companies diversity program expenses as well as various dues for specific sponsored agencies (Chamber of Commerce, social service dues, etc.)	General Allocator	Assets/Revenue/FTE Hours	Supply chain services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	43.3716%
200095	430	Energy Supply Asset Management	Energy Supply Asset Management services includes the labor and non-labor costs of providing management support to the Energy Supply organization, maximizing business value of the Energy Supply information systems, developing the business plan, optimizing plant inventory, and leading the development of asset management strategy and implementation.	General Allocator	Assets/Revenue/FTE Hours	Energy Supply Asset Management services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	43.3716%
200096	431	Energy Markets - Business Services	Energy Markets Business Services includes the labor and non-labor costs for financial analysis, budgeting and administrative support, managerial reporting and business planning and process initiatives, independent daily forward valuation and risk measurement of commodity transactions and system fuel and purchase power requirements to meet system loads, as well as proprietary or trading transactions; creates retail system load and energy forecasts providing regular updates to senior management and analyses of key drivers, reviews and provides comments to dealmakers on non-standard agreements and associated confirmation agreements in the areas of coal supply, gas supply, wood fuel, rail, trucking, structured power purchases and nuclear/uranium concentrates and services; provides analyses for electric/gas hedge studies and sensitivities; creates load management forecast, jurisdictional peak demand forecasts, and cost of service studies for energy trading and marketing.	General Allocator	Assets/Revenue/FTE Hours	Energy Markets - Business Services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	43.3716%
200097	533; 535; 539; 542	Accounting and Finance Software Applications Maintenance	Includes the labor and non-labor operating costs for the application development and maintenance of the software applications used for accounting and finance business functions.	General Allocator	Assets/Revenue/FTE Hours	CBS/ALS/CFM - The Business Systems expenses related to maintenance of this system that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	43.3716%
200098	468	Transm Elec FERC 566	Transm Elec FERC 566 services include transmission electric labor and non-labor costs associated with accounting, budgeting, regulatory reporting, and capital asset accounting.	General Allocator	Assets/Revenue/FTE Hours	Transm Elec FERC 566 charges that can not be directly charged to a specific legal entity and are corporate in nature. The three factor formula is used because these charges are comprised of a broad spectrum of activities and no measurable method of cost causative allocation was found.	43.3716%
200099	469	Elec Dist FERC 588	Elec Dist FERC 588 services include electric distribution labor and non-labor costs associated with accounting, budgeting, regulatory reporting, and capital asset accounting.	General Allocator	Assets/Revenue/FTE Hours	Elec Dist FERC 588 charges that can not be directly charged to a specific legal entity and are corporate in nature. The three factor formula is used because these charges are comprised of a broad spectrum of activities and no measurable method of cost causative allocation was found.	43.3716%
200100	134	Audit Services - OpCo's - Gas	Audit OpCo's Gas includes the labor and non-labor costs for auditing operating companies gas utility, evaluating and improving risk management, ethical conduct and the implementation of best practices for operating companies gas utility, conducting financial operations and information system audits, performing audits and reviews for compliance with regulatory and legal requirements and contracts with vendors and other parties; establishing and reviewing internal controls for operating companies gas utility, establishing and reviewing SOX compliance requirements/control testing and evaluating contract risks for the operating companies gas utility.	General Allocator	Assets/Revenue/FTE Hours	Audit Services - OpCo's - Gas services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies gas utility who benefit from the services.	50.8728%
200101	164	Legal - OpCo's - Gas	Legal OpCo Gas NSPM, NSPW and PSCo Gas services includes the labor and non-labor costs for operating companies gas utility legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts. This is primarily used by the General Counsel area.	General Allocator	Assets/Revenue/FTE Hours	Legal - OpCo's Gas services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	50.8728%
200102	470	Gas Dist FERC 880	Gas Dist FERC 880 services include gas distribution labor and non-labor costs associated with accounting, budgeting, regulatory reporting, and capital asset accounting.	General Allocator	Assets/Revenue/FTE Hours	Gas Dist FERC 880 charges that can not be directly charged to a specific legal entity and are corporate in nature. The three factor formula is used because these charges are comprised of a broad spectrum of activities and no measurable method of cost causative allocation was found.	50.8728%
200105	125	Accounting, Reporting, Tax - NSPM & NSPW	Acctg, Rptg, Tax - MN, WI includes the labor and non-labor costs associated with NSPM & NSPW revenue accounting, budgeting, regulatory reporting, sales and use taxes, business area support for utility areas, operating company budgeting support, and capital asset accounting.	General Allocator	Assets/Revenue/FTE Hours	Acctg, Rptg, Tax - MN, WI services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to NSPM & NSPW who benefit from the services.	85.8975%
200106	126	Accounting, Reporting, Tax - NSPM & NSPW Electric	Acctg, Rptg, Tax - MN, WI Elec Electric includes the labor and non-labor costs associated specifically with NSPM & NSPW Electric utility revenue accounting, budgeting, regulatory reporting, sales and use taxes, business area support for utility areas, operating company budgeting support, and capital asset accounting.	General Allocator	Assets/Revenue/FTE Hours	Acctg, Rptg, Tax - MN, WI Elec services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to NSPM & NSPW electric utility who benefit from the services.	85.8975%
200107	172	Legal - NSPM & NSPW	Legal - OpCo's services includes the labor and non-labor costs for operating companies legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts. This is primarily used by the General Counsel area.	General Allocator	Assets/Revenue/FTE Hours	Legal - NSPM & NSPW services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to NSPM & NSPW who benefit from the services.	85.8975%
200110	510	Passport - Accounts Payable	Passport - Accounts Payable includes the labor and non-labor costs for only the Accounts Payable module within Passport. This is applicable for when work is only being done on this module. This includes application development and maintenance costs, licensing fees, server system costs and technology risk costs specific to disaster recovery of this application.	Cost Causative	AP Transactions	Passport - Accounts Payable using total AP transactions to allocate costs is reasonable because there is a direct causal relationship with the companies using the AP function of Passport.	34.6463%

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Cost Center	**Work Order No.**	**Cost Center Description**	**Description of Services Provided**	**General Allocator/ Cost Causative**	**Allocation Method**	**Reasonableness of Allocation Method**	**NSPM Alloc Percent 2020**
200111	544	EAI (Enterprise Application Integration)	EAI (Enterprise Application Integration) includes the labor and non-labor costs associated with the management of information systems infrastructure and working with IT Project Managers to ensure that new systems are positioned to function as successfully as possible in terms of overall performance and communication with other systems.	Cost Causative	Average of a Select Set of Software Allocators	EAI (Entrprs Applic Integrate) using average of selected software systems to allocate costs is reasonable because EAI (Entrprs Applic Integrate) is primarily the server costs supporting the selected software applications and benefits the companies using the software applications.	39.0822%
200112	562	Mainframe Charges From IBM	Labor and non-labor costs related to Mainframe IBM expenses for development, maintenance, and licensing. The Mainframe is comprised of 3 applications: Time, Gas Management System, and Monitoring Device Management System applications. This is used primarily by the Business Systems Organization.	Cost Causative	Average of a Select Set of Software Allocators	Mainframe Charges From IBM expenses can not be directly charged to a specific legal entity as the system is used by multiple entities. Using an average of selected software systems to allocate costs is reasonable because Mainframe primarily supports these selected software systems.	27.0910%
200115	514	Miscellaneous Applications	Miscellaneous Applications includes the labor and non-labor costs associated with the management of information systems infrastructure and working with IT Project Managers to ensure that new systems are positioned to function as successfully as possible in terms of overall performance and communication with other systems.	Cost Causative	Average of All Software Percentages	Miscellaneous Applications using average of all software systems to allocate costs is reasonable because Miscellaneous Applications is primarily the server costs supporting the software applications and benefits the companies using the software applications.	35.9329%
200116	441	Distribution Electric FERC 580 (E&S)	Distribution Electric FERC 580 services includes the labor and non-labor costs for the engineering and supervision of the electric distribution organization.	Cost Causative	Electric Distribution Plant	Distribution Electric FERC 580 (E&S) using the electric distribution plant to allocate the costs is reasonable because there is a direct causal relationship with the operations supported by Distribution Electric.	35.7854%
200117	453	Transmission Electric FERC 586	Distribution Elec FERC 586 services include meter expenses labor and non-labor providing direction, operations, standards and processes relating to Xcel Energy operating companies i.e.: electric distribution meters standards and development, meter purchases, etc. This allocation is used when all four jurisdictions are benefiting from the services.	Cost Causative	Electric Distribution Plant	Distribution Elec FERC 586 using distribution plant to allocate meter costs is reasonable because there is a direct causal relationship with the electric distribution plant and meter operations supported by electric distribution.	35.7854%
200118	527	EMS Distribution - FERC 581	EMS provides supervisory control and data acquisition of substation devices through Remote Terminal Units (RTU's). EMS - Distribution system includes the labor and non-labor costs for application development and maintenance of the Electric Distribution Plant information operations. This is primarily used by the Business Systems organization.	Cost Causative	Electric Distribution Plant	EMS-Distribution (Energy Mgmt System-SCADA) using electric distribution to allocate costs is reasonable because there is a direct causal relationship with the operations supported by EMS-Distribution.	35.7854%
200119	506; 507; 559	Distribution Software Systems	Distribution Software Systems includes the labor and non-labor costs for the maintenance and support for electric and gas distribution to our customers.	Cost Causative	Electric Distribution Plant/ Gas Distribution Plant	GIS (Geographic Information System) using a ratio of elec dist plant/gas dist plant to allocate costs is reasonable because GIS is used to map these distributions systems.	33.4437%
200120	536	Design Tool	Design Tool includes the labor and non-labor operating costs for the application used to design distribution electric and gas service. This includes the application development and maintenance costs, and licensing fees.	Cost Causative	Electric Distribution Plant/ Gas Distribution Plant	Design Tool using electric distribution and gas distribution plant to allocate costs is reasonable because the costs are directly related to designing of Electric and Gas distribution system.	40.0805%
200121	474	Elec Dist, Gas Dist, & Gas Trans FERC 588, 880, 859	Elec Dist, Gas Dist, & Gas Trans FERC 588, 880, 859 services include gas distribution, gas transmission, and electric distribution labor and non-labor costs associated with accounting, budgeting, and regulatory reporting.	Cost Causative	Electric Distribution Plant/ Gas Transmission Plant/ Gas Distribution Plant	Elec Dist, Gas Dist, & Gas Trans FERC 588, 880, 859 charges that can not be directly charged to a specific business unit and are corporate in nature. Using a ratio of Electric Transmission & Gas Transmission/Distribution to allocate Utility Group costs is reasonable because there is a direct causal relationship with operations supported by Utilities Group.	31.8453%
200122	442	Transmission Electric FERC 560 (E&S)	Transmission Electric FERC 560 services includes the labor and non-labor costs for engineering and supervision of the electric transmission organization.	Cost Causative	Electric Transmission Plant	Transmission Electric FERC 560 (E&S) using Electric Transmission Plant to allocate costs is reasonable because there is a direct causal relationship with the operations supported by Transmission Electric.	34.3652%
200123	451	Transmission Electric FERC 561.5	Transmission Electric FERC 561.5 services include transmission reliability, planning and standards development labor and non-labor expenses for Xcel Energy Operating Companies related to transmission assets and reliability needs and transmission customers requirements and requests i.e.: developing and maintaining transmission system models, applying methodologies and tools for analysis and simulation of systems, notification of any planned transmission changes and impacts, etc. This allocation is used when all four jurisdictions are benefiting from the services and processes.	Cost Causative	Electric Transmission Plant	Transm Elec FERC 561.5 using electric transmission plant to allocate costs is reasonable because there is a direct causal relationship with the operations supported by Transmission Electric.	34.3652%
200124	526	EMS-Transmission (Energy Management System-SCADA)	EMS provides supervisory control and data acquisition of substation devices through Remote Terminal Units (RTU's). EMS -Transmission system includes the labor and non-labor costs for the application development and maintenance of the Electric Transmission Plant information operations.	Cost Causative	Electric Transmission Plant	EMS-Transmission (Energy Mgmt System-SCADA) using electric transmission to allocate costs is reasonable because there is a direct causal relationship with the operations supported by EMS-Transmission.	34.3652%
200125	449	Transmission Electric 560 NSPM & NSPW	Transm Elec 560 NSPM & NSPW services includes the labor and non-labor costs for NSPM & NSPW engineering and supervision of the electric transmission organization. This allocation is used when Northern States Power Company-Minnesota and Northern States Power Company-Wisconsin are the only jurisdictions benefiting from the services. This is primarily used by the Safety and Transmission and Substations organizations.	Cost Causative	Electric Transmission Plant	Transm Elec 560 NSPM & NSPW using electric transmission to allocate costs is reasonable because there is a direct causal relationship with the operations supported by Transmission Electric.	74.1481%
200126	423; 440; 525	Utilities Group Administrative & General (A&G) FERC 921	Utilities Group A&G (Administrative and General) FERC 921 services includes the labor and non-labor costs for utilities group leadership, management and support services for the distribution, transmission, transportation and supply chain areas.	Cost Causative	Electric Transmission Plant/ Electric Distribution Plant/ Gas Transmission Plant/Gas Distribution Plant	Customer & Field Operations Constr, Oper & Maint using delivery gross plant to allocate costs is reasonable because these costs are directly related to the electric and gas delivery systems.	32.8072%
200127	443	Distribution Gas FERC 870 (E&S)	Distribution Gas FERC 870 services includes the labor and non-labor costs for the engineering and supervision of the gas distribution organization.	Cost Causative	Gas Distribution Plant	Using Gas Distribution to allocate Distribution Gas FERC 870 costs is reasonable because there is a direct causal relationship with the operations supported by Distribution Gas.	27.2567%
200128	445	Distribution Gas FERC 880 (Misc.)	Distribution Gas FERC 880 services includes the labor and non-labor costs for the engineering and supervision of the gas distribution organization not provided for in FERC 870. This includes activities such as operating street lighting systems and research and development costs.	Cost Causative	Gas Distribution Plant	Distribution Gas FERC 880 (MISC) using Gas Distribution to allocate costs is reasonable because there is a direct causal relationship with the operations supported by Distribution Gas.	27.2567%
200129	454	Transmission Gas FERC 878	Distribution Gas FERC 878 services include meter expenses labor and non-labor providing direction, operations, standards and processes relating to Xcel Energy Operating Companies i.e.: gas distribution meters standards and development, meter purchases, etc. This allocation is used when all four jurisdictions are benefiting from the services.	Cost Causative	Gas Distribution Plant	Distribution Gas FERC 878 using gas distribution plant to allocate meter costs is reasonable because there is a direct causal relationship with the gas distribution plant and meter operations supported by gas distribution.	27.2567%
200130	444	Transmission Gas FERC 850 (E&S)	Transmission Gas FERC 850 services includes the labor and non-labor costs for the engineering and supervision of the gas transmission organization.	Cost Causative	Gas Transmission Plant	Distribution Gas FERC 870 (E&S) using gas transmission to allocate costs is reasonable because there is a direct causal relationship with the operations supported by transmission gas.	9.4946%
200131	531	Gas SCADA (Supervisory Control and Data Acquisition)	The Gas SCADA (Supervisory Control and Data Acquisition) system includes the labor and non-labor costs for the application development and maintenance of the Gas SCADA system. SCADA is a windows-based systems that give the gas system operators the ability to monitor and control Xcel Energy's natural gas systems. Control rooms and systems are located at both Rice Street (MN) and Lookout Center (CO).	Cost Causative	Gas Transmission Plant/ Gas Distribution Plant	Gas SCADA using a ratio of gas trans plant/gas dist plant to allocate costs is reasonable because the costs are directly related to the monitoring of gas distribution and transmission.	23.5865%
200132	413	Payment and Reporting	Payment & Reporting services includes the labor and non-labor costs associated with processing payments to vendors, providing audit research and reconciliation support for Accounts Payable transactions, preparing statistical and 1099 reporting, and administering the purchase card programs.	Cost Causative	Invoice Transactions	Payment and Reporting using invoice transactions to allocate costs is reasonable because the costs are directly related to the No. of invoices processed.	25.7281%
200133	128	Proprietary Trading - Back Office	Proprietary Trading - Back Office includes the labor and non-labor costs associated with the accounting support and vice president oversight of proprietary trading activities for Northern States Power Minnesota, Public Service Company of Colorado and Southwestern Public Service Company.	Cost Causative	Joint Operating Agreement	Prop Trading - Back Office uses the Joint Operating Agreement for cost allocations as it is required for the Prop Trade NSPM, PSCo & SPS services.	36.8539%
200134	144	Proprietary Trading - Front/Mid Office	Prop Trading - Frt/Mid Office includes the labor and non-labor costs associated with proprietary trading activities which are short term transactions undertaken in the wholesale electric markets where electricity is purchased for the purpose of selling it. Also included are supporting activities: evaluating the credit worthiness of counterparties, reviewing contracts to ensure that regulations are being complied with, evaluating profitability and appropriateness of trades to ensure they are in the best interest of shareholders and rate payers, and ensuring that trades identified as proprietary appropriately fall into that category.	General Allocator	Joint Operating Agreement	Prop Trading - Frt/Mid Office uses the Joint Operating Agreement for cost allocations as it is required for the Prop Trade NSPM, PSCo & SPS services.	44.1274%

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SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent 2020
200135	414	Energy Supply Business Resources	Energy Supply Business Resources services includes the labor and non-labor costs of performance analysis, specialists and analytical services provided to the operating companies' generation facilities.	Cost Causative	MWH Generation	Energy Supply Business Resources using MWH generation to allocate costs is reasonable because the costs are directly related to the support of the power plants.	36.2141%
200136	415	Energy Markets - Fuel	Energy Markets Fuel includes the labor and non-labor costs for planning and implementing power supply portfolios to provide reliable service to native load and to capitalize on market opportunities including purchasing fuel for the operating companies' electric generation system (excluding nuclear) and resource planning and acquisition including purchase power and account management.	Cost Causative	MWH Generation	Energy Markets - Fuel using MWH generation to allocate costs is reasonable because the costs are directly related to the purchase of fuel for generation.	36.2141%
200137	455	Energy Supply Miscellaneous Power Expense OpCo's	Energy Supply Miscellaneous Power Expense OpCo's services include Energy Supply operations performance services labor and non-labor costs for non-management employees with the following accountabilities: Develop / suggest / implement improvements for multiple power plants, standardize best practices and process improvements across multiple power plants, establish operations and maintenance policies and procedures for multiple power plants. This allocation is used when all four jurisdictions are benefiting from the services.	Cost Causative	MWH Generation	ES Misc Power Expense OpCo's using MWH generation to allocate costs is reasonable because the costs are directly related to the support of the power plants.	36.2140%
200138	458	Energy Supply Operations Management OpCo's	Energy Supply Operations Management OpCo's services include management of energy supply operations services labor and non-labor costs for the following accountabilities: Operate plant equipment within requirements, maintain plant equipment, manage plant personnel in accordance with labor contracts, suggest/implement plant improvements, maintain community relationships, establish operations and maintenance policies and procedures and overhaul planning and execution. This allocation is used when all four jurisdictions are benefiting from the services.	Cost Causative	MWH Generation	ES Operations Management OpCo's using MWH generation to allocate costs is reasonable because the costs are directly related to the support of the power plants.	36.2140%
200139	461	ES Engineering and Construction	ES Engineering & Construction OpCo's services which include management and performance labor and non-labor costs for the following accountabilities: Researching, reviewing, recommending and facilitating the selection of technological alternatives for improved plant and environmental performance. Manage uniform project management process (policies). Planning for Physical Plant Modifications, which includes consolidation and management of short-term and long-term plans for physical plant modifications. Develop and execute Innovative Technology Projects such as: Biomass, Solar, Wind. Implement enterprise project management (EPM) and planning tools. Establish uniform technology, design & equipment standards. This allocation is used when NSPM, NSPW, PSCo and SPS jurisdictions are benefiting from the services.	Cost Causative	MWH Generation	ES Engineering & Construction OpCo's using MWH generation to allocate costs is reasonable because the costs are directly related to the support of the power plants.	36.2140%
200143	456	ES Misc Power Expense NSPM & NSPW	ES Misc Power Expense North services include Energy Supply operations performance services labor and non-labor costs for non-management employees with the following accountabilities: Develop / suggest / implement improvements for multiple power plants, standardize best practices and process improvements across multiple power plants, establish operations and maintenance policies and procedures for multiple power plants. This allocation is used when NSPM & NSPW jurisdictions are benefiting from the services.	Cost Causative	MWH Generation	ES Misc Power Expense North using MWH generation to allocate costs is reasonable because the costs are directly related to the support of the power plants.	94.9940%
200144	459	ES Operations Management NSPM & NSPW	ES Operations Management North services include management of energy supply operations services labor and non-labor costs for the following accountabilities: Operate plant equipment within requirements, maintain plant equipment, manage plant personnel in accordance with labor contracts, suggest/implement plant improvements, maintain community relationships, establish operations and maintenance policies and procedures and overhaul planning and execution. This allocation is used when NSPM & NSPW jurisdictions are benefiting from the services.	Cost Causative	MWH Generation	ES Operations Management North using MWH generation to allocate costs is reasonable because the costs are directly related to the support of the power plants.	94.9940%
200145	462	ES Engineering and Construction NSPM & NSPW	Energy Supply Engineering and Construction services which include management and performance labor and non-labor costs for the following accountabilities: Researching, reviewing, recommending and facilitating the selection of technological alternatives for improved plant and environmental performance. Planning for Physical Plant Modifications, which includes consolidation and management of short-term and long-term plans for physical plant modifications. Develop and execute Innovative Technology Projects such as: Biomass, Solar, Wind. Establish uniform technology, design & equipment standards. This allocation is used when NSPM and NSPW jurisdictions are benefiting from the services.	Cost Causative	MWH Generation	ES Engineering & Construction North using MWH generation to allocate costs is reasonable because the costs are directly related to the support of the power plants.	94.9940%
200146	429	Energy Markets - Regulated Trading	Energy Markets Regulated Trading services includes the labor and non-labor costs of providing electric trading services to the operating companies' electric generation systems, including load management, system optimization and origination.	Cost Causative	MWH Hours Sold	Energy Markets - Regulated Trading (Gen Book) using MWH hours sold to allocate costs is reasonable because there is a direct casual relationship between trading activities and the MWH hours sold.	36.1188%
200147	554	Business Objects	Business Objects includes the labor and non-labor costs for the application that provides critical reporting from data universes.	Cost Causative	No. of Business Objects Users	Business Objects using No. of Business Object users to allocate costs is reasonable because the costs are directly related to users who are able to access the application.	57.5662%
200148	500; 524	Business Systems	Business Systems services includes the IT costs of providing assistance to computer users across the company. Specifically Computer technology risk, software maintenance on applications distributed to all users (i.e. Microsoft PC tools), governance and project management over all IT projects, fixed management fees with outside vendors, business analytics costs, corrective and preventative maintenance, security, data backup and recovery, help desk, and amortization of outside vendor fees and costs that are not specific to an application that has a specific allocator.	Cost Causative	No. of Computers	Business Systems using No. of computers to allocate costs is reasonable because there is a direct causal relationship between the No. of computers and the cost to support them.	51.5790%
200149	534	CES (Customer & Enterprise Solutions)	The CES includes the labor and non-labor costs for the leadership of the Customer & Enterprise Solutions organization and their administrative support staff.	Cost Causative	No. of Computers/ No. of Customers/ FTE Hours	CES using a ratio of No. of Computers/Customers/Employees to allocate costs is reasonable because there is a direct causal relationship with the operations supported by CES.	44.2047%
200150	520	IVR (Interactive Voice Response)	IVR includes the labor and non-labor costs for the application development and maintenance of the Interactive Voice Response system which interacts with a customer calling Xcel Energy call centers. It is intended to help service customers without invoking a call center agent. If the call needs to be handled by an agent, account information and the reason for the call is determined which helps route the call to the appropriate agent.	Cost Causative	No. of Contacts	IVR (Interactive Voice Response) using No. of contacts to allocate costs is reasonable because this system is used to take and route customer calls and benefits customers using the Call Centers.	34.3233%
200151	447	Customer Billing FERC 903	Customer Billing FERC 903 includes the labor and non-labor costs related to the delivery of billing statements, letters and notices to Xcel customers including postage and outside services costs, oversight and administration of customer billing area, research of billing exceptions, providing escalated customer service assistance with regard to billing issues resolution, and process remittances and receivables. This allocation is used when all four jurisdictions are benefiting from the services.	Cost Causative	No. of Customer Bills	Customer Billing FERC 903 using No. of customer bills to allocate costs is reasonable because the costs are directly related to customer billing activities.	39.3807%
200152	436	Customer Care FERC 902	Customer Care 902 services includes the labor and non-labor costs for meter reading of retail and wholesale customers and determining consumption for billing purposes as well as executing field collections.	Cost Causative	No. of Customers	Customer Care 902 using No. of customers to allocate costs is reasonable because the costs are directly related to customers.	35.3623%
200153	185	Customer Safety Advertising/Information Costs	Customer Safety Advertising and Information costs services includes the labor and non-labor costs associated with public safety advertising, information and education.	Cost Causative	No. of Customers	Customer Safety Advertising/Information Costs using No. of customers to allocate costs is reasonable because the costs are directly related to customers.	35.4109%
200154	403	Customer Service IT FERC 903	Customer Service Information Technology (IT) FERC 903 services includes the labor and non-labor costs for IT applications related customer billing to customers, call center support and credit and collections.	Cost Causative	No. of Customers	Customer Service IT - FERC 903 using No. of customers to allocate costs is reasonable because the costs are directly related to customers.	35.4109%

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SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent 2020
200155	435	Customer Care (CC) FERC 903	Customer Care (CC) 903 services includes the labor and non-labor costs for contact centers, remittance processing, credit and collections, customer resource management, and contact center training. This allocation is used when all four jurisdictions are benefiting from the services such as responding to residential customer inquiries regarding billings and outages, handling inbound credit calls, outbound collections calls, managing accounts receivables, training call center staffs, developing contact center call forecasts.	Cost Causative	No. of Customers	Customer Care 903 using No. of customers to allocate costs is reasonable because the costs are directly related to customers.	35.4109%
200156	437	Customer Care FERC 901	Customer Care 901 services includes the labor and non-labor costs for the leadership of the customer care organization and their administrative support staff such as consulting costs to support overall Customer Care organizational operations.	Cost Causative	No. of Customers	Customer Care 901 using No. of customers to costs is reasonable because the costs are directly related to customers.	35.4109%
200159	405	Customer Service IT FERC 903 - NSPM & NSPW	Customer Service IT FERC 903 - North services includes the labor and non-labor costs for IT applications related customer billing to customers, call center support and credit and collections. This allocation is used when Northern States Power Company-Min	Cost Causative	No. of Customers	Customer Service IT FERC 903 - North using No. of customers to allocate costs is reasonable because the costs are directly related to customers.	84.2065%
200160	439	Customer Care FERC 903 - NSPM & NSPW	Customer Care 903 - North services includes the labor and non-labor costs for contact centers, and credit and collections, such as responding to commercial customers inquiries at the Business Solution Center in the North. This allocation is used when Northern States Power Company-Minnesota and Northern States Power Company-Wisconsin are the only jurisdictions benefiting from the services. This is primarily used by the Customer Care organization.	Cost Causative	No. of Customers	Customer Care North 903 using No. of customers to allocate costs is reasonable because the costs are directly related to customers.	84.2065%
200161	446	Customer Care Low Income Assistance FERC 908	Customer Care Low Income Assistance (908) services includes the labor and non-labor costs associated with the low income energy customer program such as answering calls from customers for referral to low income assistance agencies, providing information to the agencies in order to process applications for assistance, take pledges/commitments from agencies and process payments from agencies.	Cost Causative	No. of Residential Customers	Customer Care Low Income Assistance 908 using No. of residential customers to allocate costs is reasonable because the costs are directly related to customers.	41.1511%
200162	519	CL/QM (Call Logging and Quality Management)	CL/QM includes the labor and non-labor operating costs for the application development and maintenance of the Call Logging and Quality Management system which is used to monitor and record calls for contact center training and leadership teams.	Cost Causative	No. of Customers/ No. of Contacts	CL/QM (Call Logging and Quality Management) using a ratio of no. of customers/no. of contacts to allocated costs is reasonable because the system benefits current and potential customers using the Call Centers.	34.8671%
200163	181	Employee Communications	Employee Communications includes the labor and non-labor costs for the development and enhancement of employee awareness and understanding of the company's strategies, priorities, decisions and performance objectives. It develops and produces regular communication vehicles, including TODAY (daily news bulleting on intranet); XTRA (monthly print publication for all employees and retirees); All Managers E-mail (real-time communication for employees who supervise and manage others); Focus on Financials for all employees; targeted communications for specific business areas, such as Human Resources, and employee meetings.	Cost Causative	FTE Hours	Employee Communications using FTE Hours to allocate costs is reasonable because the costs are directly related to employees.	45.6208%
200164	198	Payroll	Payroll services include the labor and non-labor costs for processing payroll including consolidation of time collection, calculation of salaries and wages, administration of employee deductions, account distribution and reconciliation, allocation and accounting for employment taxes and compliance reports.	Cost Causative	FTE Hours	Payroll using FTE Hours to allocate costs is reasonable because the costs are directly related to employees.	45.6208%
200165	515; 521; 552	Employee Management Systems	Employee Management Systems includes the labor and non-labor costs for the Security Operations Center (SOC), Time capture and processing for payroll and accounting and Human Resources software. These applications and services provide services for the whole company related to enterprise security, including physical access, security monitoring and investigations, payroll and time accounting and employee information databases.	Cost Causative	FTE Hours	PeopleSoft using FTE Hours to allocate costs is reasonable because the costs are directly related to employees.	45.6208%
200166	190; 197; 199	Human Resources (Diversity/Safety/Employee Relations)	Human Resources-Diversity/Safety/Employee Relations includes the labor and non-labor costs for work performed for operating and affiliate company employees, such as diversity programs, providing workforce relations resources for labor agreements, arbitration, and training. Manage, design, and implement Corporate Safety initiatives. Staffing administration for non-bargaining positions and provides Affirmative Action plans (development) and government audit management (compliance).	Cost Causative	FTE Hours	Human Resources (Diversity/Safety/Emp Relations) using FTE Hours to allocate HR costs is reasonable because the costs are directly related to employees.	45.6242%
200167	508; 550	e-Business	The e-Business system includes the labor and non-labor costs associated with the corporate electronic business infrastructure.	Cost Causative	FTE Hours	E-Business using FTE Hours to allocate costs is reasonable because the costs benefit employees.	45.6242%
200168	517	GMS (Gas Management System)	GMS supports Xcel Energy Gas Transportation business including contracts, nominations/allocations, end-user measurement, imbalance management, and input for billing. also supports gas system supply, other balancing services. Costs include labor and non-labor for the application development and maintenance of the Gas Management System.	Cost Causative	No. of Gas Customers	GMS (Gas Management System) using No. of gas customers to allocate costs is reasonable because this system benefits gas customers.	0.0017%
200169	504; 537; 553	Energy Supply Systems	Energy Supply Systems includes the labor and non-labor costs for the non-critical applications that support the Energy Supply area. Such as Emissions Tracker, Labworks, SAP WAM, Documentum and Meridian.	Cost Causative	No. of Maximo Users	Maximo using the no. of Maximo users to allocate the costs is reasonable because there is a direct causal relationship with the operations supported by Maximo.	37.2829%
200170	518; 540	Meter Reading and Monitoring Systems	Includes the labor and non-labor operating costs for the application development and maintenance of the software applications needed to read and monitor gas and electric meters.	Cost Causative	No. of Meters	MDMS (Monitoring Device Management System) using No. of meters to allocate costs is reasonable because there is a direct causal relationship with the companies using MDMS to monitor meters.	35.6505%
200171	503; 555	CRS (Customer Resource System)	The CRS system includes the labor and non-labor costs for the CRS system, specifically, application development and maintenance costs, licensing fees, server system costs and technology risk costs specific to disaster recovery of this application. CRS is Xcel Energy's customer service and billing system.	Cost Causative	No. of Meters/ No. of Contacts	CRS (Customer Resource System) using a ratio of no. of meters/no. of contacts to allocate costs is reasonable because there is a direct causal relationship with the operations supported by CRS.	34.9869%
200172	523	Network	Network services include the labor and non-labor costs for the operation, maintenance, and management of Xcel Energy's internal and external Information Technology Network. This includes circuits, firewalls and communication assets.	Cost Causative	Phones/ Radios/ Computers	Network using a ratio of phones/radios/computers to allocate costs is reasonable because the network supports these major items.	51.0395%
200173	129	Generation/Proprietary Trading - Back Office	Generation/Proprietary Trading - Back Office includes the labor and non-labor costs associated with oversight and administration of accounting related trading costs including proprietary and generation trading for Northern States Power Minnesota, Northern States Power Wisconsin, Public Service Company of Colorado and Southwestern Public Service Company.	Cost Causative	Based on labor hour allocation by Commercial Operations front office trading activities, generation (purchase and sales) and proprietary, with the proprietary allocation to NSPM, PSCo & SPS. Proprietary trading dollars are allocated based on the Joint Operating Agreement.	Gen/Prop Trading - Back Office uses a labor hour allocation based on Commercial Operations front office Generation (purchase and sales) and proprietary trading activities is reasonable because there is a direct correlation between the front office activities and the mid-office and back-office activities. It is required to use the Joint Operating Agreement for the Proprietary split for these accounting and trading costs.	37.4489%

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Cost Center	Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent 2020
200174	145	Generation/Proprietary Trading - Mid Office	Generation/Proprietary Trading - Mid Office includes the labor and non-labor costs associated with independent evaluation and risk measurement of trading and generation book transactions, including preparing daily P&L (profit and loss) reports and individual trader profit and loss reports for the prop book, daily generation book valuation reports for each system showing all net fuel positions and any forward sales values and/or hedges, ensuring that margin reporting follows all SEC rules and GAAP reporting and that credit and risk policies and procedures are complied with.	Cost Causative	Based on labor hour allocation by Commercial Operations front office trading activities, generation (purchase and sales) and proprietary, with the proprietary allocation to NSPM, PSCo & SPS. Proprietary trading dollars are allocated based on the Joint Operating Agreement.	Gen/Prop Trading - Mid Office uses a labor hour allocation based on Commercial Operations front office Generation (purchase and sales) and proprietary trading activities is reasonable because there is a direct correlation between the front office activities and the mid-office and back-office activities. It is required to use the Joint Operating Agreement for the Proprietary split for these accounting and trading costs.	41.8725%
200175	513	Passport - Purchasing	Passport - Purchasing includes the labor and non-labor costs associated with the Purchasing module within Passport. This includes application development and maintenance costs, licensing fees, server system costs and technology risk costs specific to disaster recovery of this application.	Cost Causative	Purchasing Transactions	Passport - Purchasing using purchasing transactions to allocate costs is reasonable because there is a direct causal relationship with the companies using the purchasing functions of Passport.	27.7612%
200176	412	Marketing & Sales	Marketing & Sales services includes the labor and non-labor costs for marketing and sales services for the operating companies for their customers including strategic planning, segment identification, business analysis, sales planning, customer service, promoting products to the business market, and providing regulatory and policy support with respect to utility Energy Efficiency and Demand Response program design, evaluation, measurement and verification, cost effectiveness testing , and cost recovery.	Cost Causative	Revenue	Marketing & Sales using Revenue to allocate costs is reasonable because Marketing & Sales support the revenue-producing operations of the company.	41.2063%
200177	418	Rates & Regulation - Electric	Rates & Regulation - Electric includes the labor and non-labor costs for determining the regulated utilities' electric utility revenue requirements and rates for electric customers regulatory strategy, coordinating the regulatory compliance requirements, establishing and maintaining relationships with regulatory bodies, policy development of regulatory and legislative strategy, preparing and organizing rate case filings.	Cost Causative	Revenue	Rates Electric using revenue to allocate costs is reasonable because they are responsible for setting revenue requirements.	27.2928%
200178	417	Rates & Regulation	Rates & Regulation includes the labor and non-labor costs for determining the regulated utilities' revenue requirements and rates for electric and gas customers regulatory strategy, coordinating the regulatory compliance requirements, establishing and maintaining relationships with regulatory bodies, policy development of regulatory and legislative strategy, preparing and organizing rate case filings.	Cost Causative	Revenue	Rates & Regulation using revenue to allocate costs is reasonable because they are responsible for setting revenue requirements.	27.2928%
200179	509	Passport - All Modules	Passport - All Modules includes the labor and non-labor costs for accounts payable, inventory, work management and purchasing. This includes application development and maintenance costs, licensing fees, server system costs and technology risk costs specific to disaster recovery of this application.	Cost Causative	Total AP/ Inventory/ Work Management Purchase Transactions	Passport - All Modules using the total AP/inventory/WM/purch transactions to allocate the Passport costs is reasonable because there is a direct causal relationship with the companies who benefit from Passport.	34.6297%
200180	528	EMS-Shared (Energy Management System-SCADA)	EMS provides supervisory control and data acquisition of substation devices through Remote Terminal Units (RTU's). EMS-Shared system includes the labor and non-labor costs for the application development and maintenance of the Electric Transmission, Distribution and Production Plant information operations.	Cost Causative	Electric Production Plant/ Electric Transmission Plant/ Electric Distribution Plant	EMS-Shared (Energy Mgmt System-SCADA) using a ratio of electric transmission\distribution\production to allocate costs is reasonable because there is a direct causal relationship with the operations supported by EMS-Shared.	41.8440%
200181	464	Energy Supply Environmental Policy & Services OpCo's	Energy Supply Environmental Policy & Services OpCo's services include the labor and non-labor costs dedicated to air quality, renewable energy, innovative technology and climate change, develop corporate compliance strategy, regulatory agency interaction (both at the federal and/or state level), permitting and compliance reporting, waste management, combustion byproducts management, environmental compliance auditing, provide support to the Environmental Council and assist with environmental communications strategies. This allocation is used when NSPM, NSPW, PSCo and SPS jurisdictions are benefiting from the services.	Cost Causative	Electric Production Plant/ Electric Transmission Plant/ Electric Distribution Plant/ Gas Transmission Plant/ Gas Distribution Plant	ES Environmental Policy & Services OpCo's using gross plant assets to allocate costs is reasonable because the costs are directly related to the environmental policies and services which are generated by the operation and ownership of the assets.	39.6593%
200182	465	Energy Supply Environmental Policy & Services - NSPM & NSPW	ES Environmental Policy & Services North functions which include the labor and non-labor costs dedicated to air quality, renewable energy, innovative technology and climate change, develop corporate compliance strategy, regulatory agency interaction (both at the federal and/or state level), permitting and compliance reporting, waste management, combustion byproducts management, environmental compliance auditing, provide support to the Environmental Council and assist with environmental communications strategies. This allocation is used when NSPM and NSPW jurisdictions are benefiting from the services.	Cost Causative	Electric Production Plant/ Electric Transmission Plant/ Electric Distribution Plant/ Gas Transmission Plant/ Gas Distribution Plant	ES Environmental Policy & Services North using gross plant assets to allocate costs is reasonable because the costs are directly related to the environmental policies and services which are generated by the operation and ownership of the assets.	85.7587%
200184	516	PowerPlan	PowerPlan includes the labor and non-labor operating costs for PowerPlan, which is the capital asset business system which includes the following modules. Fixed Assets, Power Tax, Property Tax, Projects, Budgets, Cost Repository, Depreciation studies and Depreciation forecast. This includes the application development and maintenance costs, licensing fees, server system costs and technology risk costs specific to disaster recovery of this application.	Cost Causative	Total Plant	PowerPlan using total plant to allocate costs is reasonable because there is a direct causal relationship with the companies using PowerPlan to manage plant assets.	42.4820%
200185	512	Passport - Work Management	Passport - Work Management includes the labor and non-labor costs associated with the Work Management module within Passport. This includes application development and maintenance costs, licensing fees, server system costs and technology risk costs specific to disaster recovery of this application.	Cost Causative	Work Management Transactions	Passport - Work Management using work management transactions to allocate costs is reasonable because there is a direct causal relationship with the companies using the work management functions of Passport.	50.4073%
200805	163	Legal - OpCo's - Electric	LEGAL OpCo Electric services includes the labor and non-labor costs for operating companies electric utility legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts. This is primarily used by the General Counsel area.	General Allocator	Assets/Revenue/FTE Hours	LEGAL OpCo Electric services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies electric utility who benefit from the services.	43.3716%
200806	173	Legal - NSPM & NSPW Electric	Legal - NSPM & NSPW Electric services includes the labor and non-labor costs for NSPM & NSPW operating companies electric legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts. This is primarily used by the General Counsel area.	General Allocator	Assets/Revenue/FTE Hours	Legal - NSPM & NSPW services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to NSPM & NSPW electric utility who benefit from the services.	85.8975%

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Allocating Cost Center	Allocating Cost Center Description	Method of Allocation	Percentage	Allocation Statistics									
200063	Executive - Corporate Governance	Asset/Revenue/Number of Employees	39.5474%	NSPM Assets - $20,877,874	Total Assets - $65,358,384	NSPM Revenues - $5,165,661	Total Revenues - $13,607,370	NSPM No. of Employees - 3,875	Total No. of Employees - 7,951				
200064	Shareholder - Corporate Governance	Asset/Revenue/Number of Employees	39.5474%	NSPM Assets - $20,877,874	Total Assets - $65,358,384	NSPM Revenues - $5,165,661	Total Revenues - $13,607,370	NSPM No. of Employees - 3,875	Total No. of Employees - 7,951				
200065	Investor Relations - Corporate Governance	Asset/Revenue/Number of Employees	39.5474%	NSPM Assets - $20,877,874	Total Assets - $65,358,384	NSPM Revenues - $5,165,661	Total Revenues - $13,607,370	NSPM No. of Employees - 3,875	Total No. of Employees - 7,951				
200066	Accounting & Reporting - Corporate Governance	Asset/Revenue/Number of Employees	39.5474%	NSPM Assets - $20,877,874	Total Assets - $65,358,384	NSPM Revenues - $5,165,661	Total Revenues - $13,607,370	NSPM No. of Employees - 3,875	Total No. of Employees - 7,951				
200067	Audit Services - Corporate Governance	Asset/Revenue/Number of Employees	39.5474%	NSPM Assets - $20,877,874	Total Assets - $65,358,384	NSPM Revenues - $5,165,661	Total Revenues - $13,607,370	NSPM No. of Employees - 3,875	Total No. of Employees - 7,951				
200068	Finance & Treasury - Corporate Governance	Asset/Revenue/Number of Employees	39.5474%	NSPM Assets - $20,877,874	Total Assets - $65,358,384	NSPM Revenues - $5,165,661	Total Revenues - $13,607,370	NSPM No. of Employees - 3,875	Total No. of Employees - 7,951				
200069	Risk Management - Corporate Governance	Asset/Revenue/Number of Employees	39.5474%	NSPM Assets - $20,877,874	Total Assets - $65,358,384	NSPM Revenues - $5,165,661	Total Revenues - $13,607,370	NSPM No. of Employees - 3,875	Total No. of Employees - 7,951				
200070	Corporate Strategy & Business Development - Corporate Governance	Asset/Revenue/Number of Employees	39.5474%	NSPM Assets - $20,877,874	Total Assets - $65,358,384	NSPM Revenues - $5,165,661	Total Revenues - $13,607,370	NSPM No. of Employees - 3,875	Total No. of Employees - 7,951				
200071	Legal - Corporate Governance	Asset/Revenue/Number of Employees	39.5474%	NSPM Assets - $20,877,874	Total Assets - $65,358,384	NSPM Revenues - $5,165,661	Total Revenues - $13,607,370	NSPM No. of Employees - 3,875	Total No. of Employees - 7,951				
200072	Communications - Corporate Governance	Asset/Revenue/Number of Employees	39.5474%	NSPM Assets - $20,877,874	Total Assets - $65,358,384	NSPM Revenues - $5,165,661	Total Revenues - $13,607,370	NSPM No. of Employees - 3,875	Total No. of Employees - 7,951				
200073	Human Resources - Corporate Governance	Asset/Revenue/Number of Employees	39.5474%	NSPM Assets - $20,877,874	Total Assets - $65,358,384	NSPM Revenues - $5,165,661	Total Revenues - $13,607,370	NSPM No. of Employees - 3,875	Total No. of Employees - 7,951				
200074	Corporate Systems	Asset/Revenue/Number of Employees	39.5474%	NSPM Assets - $20,877,874	Total Assets - $65,358,384	NSPM Revenues - $5,165,661	Total Revenues - $13,607,370	NSPM No. of Employees - 3,875	Total No. of Employees - 7,951				
200075	Board of Directors - Corporate Governance	Asset/Revenue/Number of Employees	39.5474%	NSPM Assets - $20,877,874	Total Assets - $65,358,384	NSPM Revenues - $5,165,661	Total Revenues - $13,607,370	NSPM No. of Employees - 3,875	Total No. of Employees - 7,951				
200076	Xcel Foundation	Asset/Revenue/Number of Employees	39.6459%	NSPM Assets - $20,877,874	Total Assets - $64,857,152	NSPM Revenues - $5,165,661	Total Revenues - $13,589,824	NSPM No. of Employees - 3,875	Total No. of Employees - 7,951				
200077	Branding	Asset/Revenue/Number of Employees	39.6459%	NSPM Assets - $20,877,874	Total Assets - $64,857,152	NSPM Revenues - $5,165,661	Total Revenues - $13,589,824	NSPM No. of Employees - 3,875	Total No. of Employees - 7,951				
200078	Governmental Affairs	Asset/Revenue/Number of Employees	39.6757%	NSPM Assets - $20,877,874	Total Assets - $64,677,751	NSPM Revenues - $5,165,661	Total Revenues - $13,589,824	NSPM No. of Employees - 3,875	Total No. of Employees - 7,951				
200079	Federal Lobbying	Asset/Revenue/Number of Employees	39.6757%	NSPM Assets - $20,877,874	Total Assets - $64,677,751	NSPM Revenues - $5,165,661	Total Revenues - $13,589,824	NSPM No. of Employees - 3,875	Total No. of Employees - 7,951				
200080	Capital Asset Accounting	Asset/Revenue/Number of Employees	44.3195%	NSPM Assets - $20,877,874	Total Assets - $48,575,581	NSPM Revenues - $5,165,661	Total Revenues - $12,551,254	NSPM No. of Employees - 3,875	Total No. of Employees - 7,937				
200081	Accounting, Reporting, & Taxes	Asset/Revenue/Number of Employees	44.4272%	NSPM Assets - $20,877,874	Total Assets - $48,251,439	NSPM Revenues - $5,165,661	Total Revenues - $12,540,670	NSPM No. of Employees - 3,875	Total No. of Employees - 7,937				
200082	Audit Services	Asset/Revenue/Number of Employees	44.4272%	NSPM Assets - $20,877,874	Total Assets - $48,251,439	NSPM Revenues - $5,165,661	Total Revenues - $12,540,670	NSPM No. of Employees - 3,875	Total No. of Employees - 7,937				
200083	Finance & Treasury	Asset/Revenue/Number of Employees	44.4272%	NSPM Assets - $20,877,874	Total Assets - $48,251,439	NSPM Revenues - $5,165,661	Total Revenues - $12,540,670	NSPM No. of Employees - 3,875	Total No. of Employees - 7,937				
200084	Risk Management	Asset/Revenue/Number of Employees	44.4272%	NSPM Assets - $20,877,874	Total Assets - $48,251,439	NSPM Revenues - $5,165,661	Total Revenues - $12,540,670	NSPM No. of Employees - 3,875	Total No. of Employees - 7,937				
200086	Legal	Asset/Revenue/Number of Employees	44.4272%	NSPM Assets - $20,877,874	Total Assets - $48,251,439	NSPM Revenues - $5,165,661	Total Revenues - $12,540,670	NSPM No. of Employees - 3,875	Total No. of Employees - 7,937				
200087	Accounting - OpCo's	Asset/Revenue/Number of Employees	44.4391%	NSPM Assets - $20,877,874	Total Assets - $48,228,773	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124	NSPM No. of Employees - 3,875	Total No. of Employees - 7,937				
200088	Accounting, Reporting, Tax, Audit Services - OpCo's Electric	Asset/Revenue/Number of Employees	44.4391%	NSPM Assets - $20,877,874	Total Assets - $48,228,773	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124	NSPM No. of Employees - 3,875	Total No. of Employees - 7,937				
200089	Audit Services - OpCo's	Asset/Revenue/Number of Employees	44.4391%	NSPM Assets - $20,877,874	Total Assets - $48,228,773	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124	NSPM No. of Employees - 3,875	Total No. of Employees - 7,937				
200090	Risk Management - OpCo's	Asset/Revenue/Number of Employees	44.4391%	NSPM Assets - $20,877,874	Total Assets - $48,228,773	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124	NSPM No. of Employees - 3,875	Total No. of Employees - 7,937				
200091	Captive Insurance - OpCo's	Asset/Revenue/Number of Employees	44.4391%	NSPM Assets - $20,877,874	Total Assets - $48,228,773	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124	NSPM No. of Employees - 3,875	Total No. of Employees - 7,937				
200092	Corporate Strategy & Business Development OpCo's	Asset/Revenue/Number of Employees	44.4391%	NSPM Assets - $20,877,874	Total Assets - $48,228,773	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124	NSPM No. of Employees - 3,875	Total No. of Employees - 7,937				
200093	Legal - OpCo's	Asset/Revenue/Number of Employees	44.4391%	NSPM Assets - $20,877,874	Total Assets - $48,228,773	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124	NSPM No. of Employees - 3,875	Total No. of Employees - 7,937				
200094	Supply Chain	Asset/Revenue/Number of Employees	44.4391%	NSPM Assets - $20,877,874	Total Assets - $48,228,773	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124	NSPM No. of Employees - 3,875	Total No. of Employees - 7,937				
200095	Energy Supply Asset Management	Asset/Revenue/Number of Employees	44.4391%	NSPM Assets - $20,877,874	Total Assets - $48,228,773	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124	NSPM No. of Employees - 3,875	Total No. of Employees - 7,937				
200096	Energy Markets - Business Services	Asset/Revenue/Number of Employees	44.4391%	NSPM Assets - $20,877,874	Total Assets - $48,228,773	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124	NSPM No. of Employees - 3,875	Total No. of Employees - 7,937				
200097	Accounting and Finance Software Applications Maintenance	Asset/Revenue/Number of Employees	44.4391%	NSPM Assets - $20,877,874	Total Assets - $48,228,773	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124	NSPM No. of Employees - 3,875	Total No. of Employees - 7,937				
200098	Transm Elec FERC 566	Asset/Revenue/Number of Employees	44.4391%	NSPM Assets - $20,877,874	Total Assets - $48,228,773	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124	NSPM No. of Employees - 3,875	Total No. of Employees - 7,937				
200099	Elec Dist FERC 588	Asset/Revenue/Number of Employees	44.4391%	NSPM Assets - $20,877,874	Total Assets - $48,228,773	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124	NSPM No. of Employees - 3,875	Total No. of Employees - 7,937				
200100	Audit Services - OpCo's - Gas	Asset/Revenue/Number of Employees	52.0411%	NSPM Assets - $20,877,874	Total Assets - $41,435,452	NSPM Revenues - $5,165,661	Total Revenues - $10,601,381	NSPM No. of Employees - 3,875	Total No. of Employees - 6,797				
200101	Legal - OpCo's - Gas	Asset/Revenue/Number of Employees	52.0411%	NSPM Assets - $20,877,874	Total Assets - $41,435,452	NSPM Revenues - $5,165,661	Total Revenues - $10,601,381	NSPM No. of Employees - 3,875	Total No. of Employees - 6,797				
200102	Gas Dist FERC 880	Asset/Revenue/Number of Employees	52.0411%	NSPM Assets - $20,877,874	Total Assets - $41,435,452	NSPM Revenues - $5,165,661	Total Revenues - $10,601,381	NSPM No. of Employees - 3,875	Total No. of Employees - 6,797				
200105	Accounting, Reporting, Tax - NSPM & NSPW	Asset/Revenue/Number of Employees	86.4582%	NSPM Assets - $20,877,874	Total Assets - $23,684,167	NSPM Revenues - $5,165,661	Total Revenues - $6,186,854	NSPM No. of Employees - 3,875	Total No. of Employees - 4,417				
200106	Accounting, Reporting, Tax - NSPM & NSPW Electric	Asset/Revenue/Number of Employees	86.4582%	NSPM Assets - $20,877,874	Total Assets - $23,684,167	NSPM Revenues - $5,165,661	Total Revenues - $6,186,854	NSPM No. of Employees - 3,875	Total No. of Employees - 4,417				
200107	Legal - NSPM & NSPW	Asset/Revenue/Number of Employees	86.4582%	NSPM Assets - $20,877,874	Total Assets - $23,684,167	NSPM Revenues - $5,165,661	Total Revenues - $6,186,854	NSPM No. of Employees - 3,875	Total No. of Employees - 4,417				
200110	Passport - Accounts Payable	Accounts Payable Transactions	34.6463%	NSPM No. of AP Transactions - 463,450	Total No. of AP Transactions - 1,337,662								
200111	EAI (Enterprise Application Integration)	Average of a Select Set of Software Allocators	39.6838%	NSPM Percentage - 39.6838%	Total Percent - 100%								
200112	Mainframe Charges From IBM	Average of a Select Set of Software Allocators	28.1294%	NSPM Percentage - 28.1294%	Total Percent - 100%								
200115	Miscellaneous Applications	Average of all Software Percentages	36.3060%	NSPM Percentage - 36.3060%	Total Percent - 100%								
200116	Distribution Electric FERC 580 (E&S)	Electric Distribution Plant	35.7854%	NSPM Gross Electric Dist Plant - $4,179,778	Total Gross Electric Dist Plant - $11,680,123								
200117	Transmission Electric FERC 586	Electric Distribution Plant	35.7854%	NSPM Gross Electric Dist Plant - $4,179,778	Total Gross Electric Dist Plant - $11,680,123								
200118	EMS Distribution - FERC 581	Electric Distribution Plant	35.7854%	NSPM Gross Electric Dist Plant - $4,179,778	Total Gross Electric Dist Plant - $11,680,123								
200119	Distribution Software Systems	Electric Distribution Plant/ Gas Distribution Plant	33.4437%	NSPM Gross Electric Dist Plant - $4,179,778	Total Gross Electric Dist Plant - $11,680,123	NSPM Gross Gas Dist Plant - $1,205,016	Total Gross Gas Dist Plant - $4,420,992						
200120	Design Tool	Electric Distribution Plant/ Gas Distribution Plant	40.0805%	NSPM Gross Electric Dist Plant - $4,179,778	Total Gross Electric Dist Plant - $9,318,892	NSPM Gross Gas Dist Plant - $1,205,016	Total Gross Gas Dist Plant - $4,116,060						
200121	Elec Dist, Gas Dist, & Gas Trans FERC 588, 880, 859	Electric Distribution Plant/ Gas Transmission Plant/ Gas Distribution Plant	31.8453%	NSPM Gross Electric Dist Plant - $4,179,778	Total Gross Electric Dist Plant - $11,680,123	NSPM Gross Gas Trans Plant - $109,325	Total Gross Gas Trans Plant - $1,151,445	NSPM Gross Gas Dist Plant - $1,205,016	Total Gross Gas Dist Plant - $4,420,992				
200122	Transmission Electric FERC 560 (E&S)	Electric Transmission Plant	34.3652%	NSPM Gross Electric Trans Plant - $3,661,017	Total Gross Electric Trans Plant - $10,653,295								
200123	Transmission Electric FERC 561.5	Electric Transmission Plant	34.3652%	NSPM Gross Electric Trans Plant - $3,661,017	Total Gross Electric Trans Plant - $10,653,295								
200124	EMS-Transmission (Energy Management System-SCADA)	Electric Transmission Plant	34.3652%	NSPM Gross Electric Trans Plant - $3,661,017	Total Gross Electric Trans Plant - $10,653,295								
200125	Transmission Electric 560 NSPM & NSPW	Electric Transmission Plant	74.1481%	NSPM Gross Electric Trans Plant - 3,661,017	Total Gross Electric Trans Plant - 4,937,436								
200126	Utilities Group Administrative & General (A&G) FERC 921	Delivery Gross Plant	32.8072%	NSPM Gross Electric Trans Plant - $3,661,017	Total Gross Electric Trans Plant - $10,653,295	NSPM Gross Electric Dist Plant - $4,179,778	Total Gross Electric Dist Plant - $11,680,123	NSPM Gross Gas Trans Plant - $109,325	Total Gross Gas Trans Plant - $1,151,445	NSPM Gross Gas Dist Plant - $1,205,016	Total Gross Gas Dist Plant - $4,420,992		
200127	Distribution Gas FERC 870 (E&S)	Gas Distribution Plant	27.2567%	NSPM Gross Gas Dist Plant - $1,205,016	Total Gross Gas Dist Plant - $4,420,992								

2020 Test Year Budget

Allocating Cost Center	Allocating Cost Center Description	Method of Allocation	Percentage	Allocation Statistics									
200128	Distribution Gas FERC 880 (Misc.)	Gas Distribution Plant	27.2567%	NSPM Gross Gas Dist Plant - $1,205,016	Total Gross Gas Dist Plant - $4,420,992								
200129	Transmission Gas FERC 878	Gas Distribution Plant	27.2567%	NSPM Gross Gas Dist Plant - $1,205,016	Total Gross Gas Dist Plant - $4,420,992								
200130	Transmission Gas FERC 850 (E&S)	Gas Transmission Plant	9.4946%	NSPM Gross Gas Trans Plant - $109,325	Total Gross Gas Trans Plant - $1,151,445								
200131	Gas SCADA (Supervisory Control and Data Acquisition)	Gas Transmission Plant/ Gas Distribution Plant	23.5865%	NSPM Gross Gas Trans Plant - $109,325	Total Gross Gas Trans Plant - $1,151,445	NSPM Gross Gas Dist Plant - $1,205,016	Total Gross Gas Dist Plant - $4,420,992						
200132	Payment and Reporting	Invoice Transactions	25.7281%	NSPM Invoice Transactions - 131,449	Total Invoice Transactions - 510,917								
200133	Proprietary Trading - Back Office	Joint Operating Agreement Peak Hour Megawatt Load Ratio	36.8539%	NSPM Peak MWH - 7,452	Total Peak MWH - 20,221								
200134	Proprietary Trading - Front/Mid Office	Joint Operating Agreement Peak Hour Megawatt Load Ratio	44.1274%	NSP Peak MWH - 8,923	Total Peak MWH - 20,221								
200135	Energy Supply Business Resources	MWH Generation (000's)	36.2141%	NSPM MWH Generation - 22,480,817	Total MWH Generation - 62,077,597								
200136	Energy Markets - Fuel	MWH Generation (000's)	36.2141%	NSPM MWH Generation - 22,480,817	Total MWH Generation - 62,077,597								
200137	Energy Supply Miscellaneous Power Expense OpCo's	MWH Generation (000's)	36.2140%	NSPM MWH Generation - 22,480,817	Total MWH Generation - 62,077,597								
200138	Energy Supply Operations Management OpCo's	MWH Generation (000's)	36.2140%	NSPM MWH Generation - 22,480,817	Total MWH Generation - 62,077,597								
200139	ES Engineering and Construction	MWH Generation (000's)	36.2140%	NSPM MWH Generation - 22,480,817	Total MWH Generation - 62,077,597								
200143	ES Misc Power Expense NSPM & NSPW	MWH Generation (000's)	94.9940%	NSPM MWH Generation - 22,480,817	Total MWH Generation - 23,665,519								
200144	ES Operations Management NSPM & NSPW	MWH Generation (000's)	94.9940%	NSPM MWH Generation - 22,480,817	Total MWH Generation - 23,665,519								
200145	ES Engineering & Construction NSPM & NSPW	MWH Generation (000's)	94.9940%	NSPM MWH Generation - 22,480,817	Total MWH Generation - 23,665,519								
200146	Energy Markets - Regulated Trading	MWH Hours Sold (000's)	36.1188%	NSPM MWh Hour Sales - 41,727,467	Total MWh Hour Sales - 115,528,442								
200147	Business Objects	Number of Business Objects Users	57.5662%	NSPM No. of Business Objects users - 2,758	Total No. of Business Objects users - 4,791								
200148	Business Systems	Number of Computers	51.5790%	NSPM No. of Computers - 5,749	Total No. of Computers - 11,146								
200149	CES (Customer & Enterprise Solutions)	Number of - Computers/Customers/Employees	45.2706%	NSPM No. of Computers - 5,749	Total No. of Computers - 11,146	NSPM No. of Customers - 1,995,181	Total No. of Customers - 5,634,323	NSPM No. of Employees - 3,875	Total No. of Employees - 7,937				
200150	IVR (Interactive Voice Response)	Number of Contacts	34.3233%	NSPM No. of Contacts - 1,452,629	Total No. of Contacts - 4,232,193								
200151	Customer Billing FERC 903	Number of Customer Bills	39.3807%	NSPM No. of Customer Bills - 1,501,239	Total No. of Customer Bills - 3,812,122								
200152	Customer Care FERC 902	Number of Customers	35.3623%	NSPM No. of Customers - 1,995,181	Total No. of Customers - 5,642,116								
200153	Customer Safety Advertising/Information Costs	Number of Customers	35.4109%	NSPM No. of Customers - 1,995,181	Total No. of Customers - 5,634,323								
200154	Customer Service IT FERC 903	Number of Customers	35.4109%	NSPM No. of Customers - 1,995,181	Total No. of Customers - 5,634,323								
200155	Customer Care (CC) FERC 903	Number of Customers	35.4109%	NSPM No. of Customers - 1,995,181	Total No. of Customers - 5,634,323								
200156	Customer Care FERC 901	Number of Customers	35.4109%	NSPM No. of Customers - 1,995,181	Total No. of Customers - 5,634,323								
200159	Customer Service IT FERC 903 - NSPM & NSPW	Number of Customers	84.2065%	NSPM No. of Customers - 1,995,181	Total No. of Customers - 2,369,374								
200160	Customer Care FERC 903 - NSPM & NSPW	Number of Customers	84.2065%	NSPM No. of Customers - 1,995,181	Total No. of Customers - 2,369,374								
200161	Customer Care Low Income Assistance FERC 908	Number of Residential Customers/Number of Calls	41.1511%	NSPM No. of Residential Customers - 1,785,675	Total No. of Residential Customers - 4,969,497	NSPM No. of Calls - 53,616	Total No. of Calls - 115,628						
200162	CL/QM (Call Logging and Quality Management)	Number of Customers/Number of Contacts	34.8671%	NSPM No. of Customers - 1,995,181	Total No. of Customers - 5,634,323	NSPM No. of Contacts - 1,452,629	Total No. of Contacts - 4,232,193						
200163	Employee Communications	Number of Employees	48.7360%	NSPM No. of Employees - 3,875	Total No. of Employees - 7,951								
200164	Payroll	Number of Employees	48.7360%	NSPM No. of Employees - 3,875	Total No. of Employees - 7,951								
200165	Employee Management Systems	Number of Employees	48.7360%	NSPM No. of Employees - 3,875	Total No. of Employees - 7,951								
200166	Human Resources (Diversity/Safety/Employee Relations)	Number of Employees	48.8220%	NSPM No. of Employees - 3,875	Total No. of Employees - 7,937								
200167	e-Business	Number of Employees	48.8220%	NSPM No. of Employees - 3,875	Total No. of Employees - 7,937								
200168	GMS (Gas Management System)	Number of Gas Customers (incl Transp Cust)	0.0017%	NSPM No. of Gas Transport Customers - 26	Total No. of Gas Transport Customers - 7,843								
200169	Energy Supply Systems	Number of Energy Supply WAM Users	37.2829%	NSPM No. of WAM ES Users - 601	Total No. of WAM ES Users - 1,612								
200170	Meter Reading and Monitoring Systems	Number of Meters	35.6505%	NSPM No. of Meters - 2,032,504	Total No. of Meters - 5,701,198								
200171	CRS (Customer Resource System)	Number of Meters/Number of Contacts	34.9869%	NSPM No. of Meters - 2,032,504	Total No. of Meters - 5,701,198	NSPM No. of Contacts - 1,452,629	Total No. of Contacts - 4,232,193						
200172	Network	Phones/Radios/Computers	51.0395%	NSPM No. of Phones - 5,908	Total No. of Phones - 10,487	NSPM No. of Radios - 2,450	Total No. of Radios - 5,420	NSPM No. of Computers - 5,749	Total No. of Computers - 11,146				
200173	Generation/Proprietary Trading - Back Office	Joint Operating Agreement Labor Hours Ratio	37.4489%	NSPM Percentage - 37.4489%	Total Percent - 100%								
200174	Generation/Proprietary Trading - Mid Office	Joint Operating Agreement Labor Hours Ratio	41.8725%	NSP Percentage - 41.8725%	Total Percent - 100%								
200175	Passport - Purchasing	Purchasing Transactions	27.7612%	NSPM No. of Passport Purchasing Transactions - 95,692	Total No. of Passport Purchasing Transactions - 344,697								
200176	Marketing & Sales	Revenue	41.2063%	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124								
200177	Rates & Regulation - Electric	Direct Labor	27.2928%	NSPM Direct Labor - $1,663,237	Total Direct Labor - $6,094,059								
200178	Rates & Regulation	Direct Labor	27.2928%	NSPM Direct Labor - $1,663,237	Total Direct Labor - $6,094,059								
200179	Passport - All Modules	Total AP/ Inventory/ Work Management/ Purchase Transactions	34.6297%	NSPM No. of AP Transactions - 463,450	Total No. of AP Transactions - 1,337,662	NSPM No. of Passport Inventory Transactions - 165,063	Total No. of Passport Inventory Transactions - 495,278	NSPM No. of Passport Work Mgmt Transactions - 95,541	Total No. of Passport Work Mgmt Transactions - 189,538	NSPM No. of Passport Purchasing Transactions - 95,692	Total No. of Passport Purchasing Transactions - 344,697		
200180	EMS-Shared (Energy Management System-SCADA)	Electric Production Plant/ Electric Transmission Plant/ Electric Distribution Plant	41.8440%	NSPM Gross Electric Prod Plant - $9,314,980	Total Gross Electric Prod Plant - $18,666,109	NSPM Gross Electric Trans Plant - $3,661,017	Total Gross Electric Trans Plant - $10,653,295	NSPM Gross Electric Dist Plant - $4,179,778	Total Gross Electric Dist Plant - $11,680,123				
200181	Energy Supply Environmental Policy & Services OpCo's	Gross Plant Assets	39.6593%	NSPM Gross Electric Prod Plant - $9,314,980	Total Gross Electric Prod Plant - $18,666,109	NSPM Gross Electric Trans Plant - $3,661,017	Total Gross Electric Trans Plant - $10,653,295	NSPM Gross Electric Dist Plant - $4,179,778	Total Gross Electric Dist Plant - $11,680,123	NSPM Gross Gas Trans Plant - $109,325	Total Gross Gas Trans Plant - $1,151,445	NSPM Gross Gas Dist Plant - $1,205,016	Total Gross Gas Dist Plant - $4,420,992
200182	Energy Supply Environmental Policy & Services - NSPM & NSPW	Gross Plant Assets	85.7587%	NSPM Gross Electric Prod Plant - $9,314,980	Total Gross Electric Prod Plant - $9,829,199	NSPM Gross Electric Trans Plant - $3,661,017	Total Gross Electric Trans Plant - $4,937,436	NSPM Gross Electric Dist Plant - $4,179,778	Total Gross Electric Dist Plant - $5,151,411	NSPM Gross Gas Trans Plant - $109,325	Total Gross Gas Trans Plant - $109,325	NSPM Gross Gas Dist Plant - $1,205,016	Total Gross Gas Dist Plant - $304,932
200184	PowerPlan	Total Plant	42.4820%	NSPM Plant Assets - $23,412,451	Total Plant Assets - $55,111,479								
200185	Passport - Work Management	Work Management Transactions	50.4073%	NSPM No. of Passport Work Mgmt Transactions - 95,541	Total No. of Passport Work Mgmt Transactions - 189,538								
200805	Legal - OpCo's - Electric	Asset/Revenue/Number of Employees	44.4391%	NSPM Assets - $20,877,874	Total Assets - $48,228,773	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124	NSPM No. of Employees - 3,875	Total No. of Employees - 7,937				
200806	Legal - NSPM & NSPW Electric	Asset/Revenue/Number of Employees	86.4582%	NSPM Assets - $20,877,874	Total Assets - $23,684,167	NSPM Revenues - $5,165,661	Total Revenues - $6,186,854	NSPM No. of Employees - 3,875	Total No. of Employees - 4,417				

Statistics for Service Company Allocations - Using the Allocated FTE Method

2020 Test Year Budget

Allocating Cost Center	Allocating Cost Center Description	Method of Allocation	Percentage	Allocation Statistics					
200063	Executive - Corporate Governance	Assets/Revenue/FTE Labor Hours	38.5025%	NSPM Assets - $20,877,874	Total Assets - $65,358,384	NSPM Revenues - $5,165,661	Total Revenues - $13,607,370	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,707,040
200064	Shareholder - Corporate Governance	Assets/Revenue/FTE Labor Hours	38.5025%	NSPM Assets - $20,877,874	Total Assets - $65,358,384	NSPM Revenues - $5,165,661	Total Revenues - $13,607,370	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,707,040
200065	Investor Relations - Corporate Governance	Assets/Revenue/FTE Labor Hours	38.5025%	NSPM Assets - $20,877,874	Total Assets - $65,358,384	NSPM Revenues - $5,165,661	Total Revenues - $13,607,370	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,707,040
200066	Accounting & Reporting - Corporate Governance	Assets/Revenue/FTE Labor Hours	38.5025%	NSPM Assets - $20,877,874	Total Assets - $65,358,384	NSPM Revenues - $5,165,661	Total Revenues - $13,607,370	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,707,040
200067	Audit Services - Corporate Governance	Assets/Revenue/FTE Labor Hours	38.5025%	NSPM Assets - $20,877,874	Total Assets - $65,358,384	NSPM Revenues - $5,165,661	Total Revenues - $13,607,370	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,707,040
200068	Finance & Treasury - Corporate Governance	Assets/Revenue/FTE Labor Hours	38.5025%	NSPM Assets - $20,877,874	Total Assets - $65,358,384	NSPM Revenues - $5,165,661	Total Revenues - $13,607,370	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,707,040
200069	Risk Management - Corporate Governance	Assets/Revenue/FTE Labor Hours	38.5025%	NSPM Assets - $20,877,874	Total Assets - $65,358,384	NSPM Revenues - $5,165,661	Total Revenues - $13,607,370	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,707,040
200070	Corporate Strategy & Business Development - Corporate Governance	Assets/Revenue/FTE Labor Hours	38.5025%	NSPM Assets - $20,877,874	Total Assets - $65,358,384	NSPM Revenues - $5,165,661	Total Revenues - $13,607,370	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,707,040
200071	Legal - Corporate Governance	Assets/Revenue/FTE Labor Hours	38.5025%	NSPM Assets - $20,877,874	Total Assets - $65,358,384	NSPM Revenues - $5,165,661	Total Revenues - $13,607,370	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,707,040
200072	Communications - Corporate Governance	Assets/Revenue/FTE Labor Hours	38.5025%	NSPM Assets - $20,877,874	Total Assets - $65,358,384	NSPM Revenues - $5,165,661	Total Revenues - $13,607,370	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,707,040
200073	Human Resources - Corporate Governance	Assets/Revenue/FTE Labor Hours	38.5025%	NSPM Assets - $20,877,874	Total Assets - $65,358,384	NSPM Revenues - $5,165,661	Total Revenues - $13,607,370	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,707,040
200074	Corporate Systems	Assets/Revenue/FTE Labor Hours	38.5025%	NSPM Assets - $20,877,874	Total Assets - $65,358,384	NSPM Revenues - $5,165,661	Total Revenues - $13,607,370	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,707,040
200075	Board of Directors - Corporate Governance	Assets/Revenue/FTE Labor Hours	38.5025%	NSPM Assets - $20,877,874	Total Assets - $65,358,384	NSPM Revenues - $5,165,661	Total Revenues - $13,607,370	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,707,040
200076	Xcel Foundation	Assets/Revenue/FTE Labor Hours	38.6056%	NSPM Assets - $20,877,874	Total Assets - $64,857,152	NSPM Revenues - $5,165,661	Total Revenues - $13,589,824	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,700,638
200077	Branding	Assets/Revenue/FTE Labor Hours	38.6055%	NSPM Assets - $20,877,874	Total Assets - $64,857,152	NSPM Revenues - $5,165,661	Total Revenues - $13,589,824	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,700,638
200078	Governmental Affairs	Assets/Revenue/FTE Labor Hours	38.6356%	NSPM Assets - $20,877,874	Total Assets - $64,677,751	NSPM Revenues - $5,165,661	Total Revenues - $13,589,824	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,700,204
200079	Federal Lobbying	Assets/Revenue/FTE Labor Hours	38.6356%	NSPM Assets - $20,877,874	Total Assets - $64,677,751	NSPM Revenues - $5,165,661	Total Revenues - $13,589,824	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,700,204
200080	Capital Asset Accounting	Assets/Revenue/FTE Labor Hours	43.2479%	NSPM Assets - $20,877,874	Total Assets - $48,575,581	NSPM Revenues - $5,165,661	Total Revenues - $12,551,254	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,704,379
200081	Accounting, Reporting, & Taxes	Assets/Revenue/FTE Labor Hours	43.3596%	NSPM Assets - $20,877,874	Total Assets - $48,251,439	NSPM Revenues - $5,165,661	Total Revenues - $12,540,670	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,698,800
200082	Audit Services	Assets/Revenue/FTE Labor Hours	43.3596%	NSPM Assets - $20,877,874	Total Assets - $48,251,439	NSPM Revenues - $5,165,661	Total Revenues - $12,540,670	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,698,800
200083	Finance & Treasury	Assets/Revenue/FTE Labor Hours	43.3596%	NSPM Assets - $20,877,874	Total Assets - $48,251,439	NSPM Revenues - $5,165,661	Total Revenues - $12,540,670	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,698,800
200084	Risk Management	Assets/Revenue/FTE Labor Hours	43.3596%	NSPM Assets - $20,877,874	Total Assets - $48,251,439	NSPM Revenues - $5,165,661	Total Revenues - $12,540,670	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,698,800
200086	Legal	Assets/Revenue/FTE Labor Hours	43.3596%	NSPM Assets - $20,877,874	Total Assets - $48,251,439	NSPM Revenues - $5,165,661	Total Revenues - $12,540,670	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,698,800
200087	Accounting - OpCo's	Assets/Revenue/FTE Labor Hours	43.3716%	NSPM Assets - $20,877,874	Total Assets - $48,228,773	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,698,585
200088	Accounting, Reporting, Tax, Audit Services - OpCo's Electric	Assets/Revenue/FTE Labor Hours	43.3716%	NSPM Assets - $20,877,874	Total Assets - $48,228,773	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,698,585
200089	Audit Services - OpCo's	Assets/Revenue/FTE Labor Hours	43.3716%	NSPM Assets - $20,877,874	Total Assets - $48,228,773	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,698,585
200090	Risk Management - OpCo's	Assets/Revenue/FTE Labor Hours	43.3716%	NSPM Assets - $20,877,874	Total Assets - $48,228,773	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,698,585
200091	Captive Insurance - OpCo's	Assets/Revenue/FTE Labor Hours	43.3716%	NSPM Assets - $20,877,874	Total Assets - $48,228,773	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,698,585
200092	Corporate Strategy & Business Development OpCo's	Assets/Revenue/FTE Labor Hours	43.3716%	NSPM Assets - $20,877,874	Total Assets - $48,228,773	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,698,585
200093	Legal - OpCo's	Assets/Revenue/FTE Labor Hours	43.3716%	NSPM Assets - $20,877,874	Total Assets - $48,228,773	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,698,585
200094	Supply Chain	Assets/Revenue/FTE Labor Hours	43.3716%	NSPM Assets - $20,877,874	Total Assets - $48,228,773	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,698,585
200095	Energy Supply Asset Management	Assets/Revenue/FTE Labor Hours	43.3716%	NSPM Assets - $20,877,874	Total Assets - $48,228,773	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,698,585
200096	Energy Markets - Business Services	Assets/Revenue/FTE Labor Hours	43.3716%	NSPM Assets - $20,877,874	Total Assets - $48,228,773	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,698,585
200097	Accounting and Finance Software Applications Maintenance	Assets/Revenue/FTE Labor Hours	43.3716%	NSPM Assets - $20,877,874	Total Assets - $48,228,773	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,698,585
200098	Transm Elec FERC 566	Assets/Revenue/FTE Labor Hours	43.3716%	NSPM Assets - $20,877,874	Total Assets - $48,228,773	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,698,585
200099	Elec Dist FERC 588	Assets/Revenue/FTE Labor Hours	43.3716%	NSPM Assets - $20,877,874	Total Assets - $48,228,773	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,698,585
200100	Audit Services - OpCo's - Gas	Assets/Revenue/FTE Labor Hours	50.8728%	NSPM Assets - $20,877,874	Total Assets - $41,435,452	NSPM Revenues - $5,165,661	Total Revenues - $10,601,381	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 18,500,446
200101	Legal - OpCo's - Gas	Assets/Revenue/FTE Labor Hours	50.8728%	NSPM Assets - $20,877,874	Total Assets - $41,435,452	NSPM Revenues - $5,165,661	Total Revenues - $10,601,381	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 18,500,446
200102	Gas Dist FERC 880	Assets/Revenue/FTE Labor Hours	50.8728%	NSPM Assets - $20,877,874	Total Assets - $41,435,452	NSPM Revenues - $5,165,661	Total Revenues - $10,601,381	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 18,500,446
200105	Accounting, Reporting, Tax - NSPM & NSPW	Assets/Revenue/FTE Labor Hours	85.8975%	NSPM Assets - $20,877,874	Total Assets - $23,684,167	NSPM Revenues - $5,165,661	Total Revenues - $6,186,854	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 11,503,882
200106	Accounting, Reporting, Tax - NSPM & NSPW Electric	Assets/Revenue/FTE Labor Hours	85.8975%	NSPM Assets - $20,877,874	Total Assets - $23,684,167	NSPM Revenues - $5,165,661	Total Revenues - $6,186,854	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 11,503,882

2020 Test Year Budget

Allocating Cost Center	Allocating Cost Center Description	Method of Allocation	Percentage	Allocation Statistics					
200107	Legal - NSPM & NSPW	Assets/Revenue/FTE Labor Hours	85.8975%	NSPM Assets - $20,877,874	Total Assets - $23,684,167	NSPM Revenues - $5,165,661	Total Revenues - $6,186,854	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 11,503,882
200111	EAI (Enterprise Application Integration)	Average of a Select Set of Software Allocators	39.0822%	NSPM Percentage - 39.0822%	Total Percent - 100%				
200112	Mainframe Charges From IBM	Average of a Select Set of Software Allocators	27.0910%	NSPM Percentage - 27.0910%	Total Percent - 100%				
200115	Miscellaneous Applications	Average of all Software Percentages	35.9329%	NSPM Percentage - 35.9329%	Total Percent - 100%				
200149	CES (Customer & Enterprise Solutions)	Number of - Computers/Customers/FTE Labor Hours	44.2047%	NSPM No. of Computers - 5,749	Total No. of Computers - 11,146	NSPM No. of Customers - 1,995,181	Total No. of Customers - 5,634,323	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,696,279
200163	Employee Communications	FTE Labor Hours	45.6208%	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,697,898				
200164	Payroll	FTE Labor Hours	45.6208%	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,697,898				
200165	Employee Management Systems	FTE Labor Hours	45.6208%	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,697,898				
200166	Human Resources (Diversity/Safety/Employee Relations)	FTE Labor Hours	45.6242%	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,696,279				
200167	e-Business	FTE Labor Hours	45.6242%	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,696,279				
200805	Legal - OpCo's - Electric	Assets/Revenue/FTE Labor Hours	43.3716%	NSPM Assets - $20,877,874	Total Assets - $48,228,773	NSPM Revenues - $5,165,661	Total Revenues - $12,536,124	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 21,698,585
200806	Legal - NSPM & NSPW Electric	Assets/Revenue/FTE Labor Hours	85.8975%	NSPM Assets - $20,877,874	Total Assets - $23,684,167	NSPM Revenues - $5,165,661	Total Revenues - $6,186,854	NSPM FTE Labor Hours - 9,898,756	Total FTE Labor Hours - 11,503,882

Northern States Power Company

Impact to NSPM 2020 Test Year for Change in XES Allocations
Using FTE Methods Instead of Number of Employees

2020 Budget Test Year

Allocating Cost Center	Work Order Title		Employee Headcount Method	FTE Method	Variance	XES Total Amount (2020 Budget)	NSPM Total Company Amount (Headcount)	NSPM Total Company Amount (FTE)	NSPM Total Impact	NSPM Elec	MN Elec	ND Elec	SD Elec	NSPM Gas	MN Gas	ND Gas
										E/G Allocator	Two Factor Jurisictional Allocator			E/G Allocator	Customer Allocator	
										91.54%	87.06%	6.23%	6.71%	8.46%	88.75%	11.25%
200063	Executive - Corporate Governance	Assets/Revenue/No. of Employees (Corp Gov)	39.5474%	38.5025%	-1.0449%	$ 71,799,864	$ 28,394,980	$ 27,644,743	$ (750,237)	$ (686,749)	$ (597,899)	$ (42,768)	$ (46,082)	$ (63,488)	$ (56,346)	$ (7,142)
200064	Shareholder - Corporate Governance	Assets/Revenue/No. of Employees (Corp Gov)	39.5474%	38.5025%	-1.0449%	240,996	95,308	92,789	(2,519)	(2,306)	(2,008)	(144)	(155)	(213)	(189)	(24)
200065	Investor Relations - Corporate Governance	Assets/Revenue/No. of Employees (Corp Gov)	39.5474%	38.5025%	-1.0449%	2,272,465	898,701	874,956	(23,745)	(21,735)	(18,923)	(1,354)	(1,458)	(2,009)	(1,783)	(226)
200066	Accounting & Reporting - Corporate Governance	Assets/Revenue/No. of Employees (Corp Gov)	39.5474%	38.5025%	-1.0449%	19,381,387	7,664,835	7,462,318	(202,517)	(185,379)	(161,395)	(11,545)	(12,439)	(17,138)	(15,210)	(1,928)
200067	Audit Services - Corporate Governance	Assets/Revenue/No. of Employees (Corp Gov)	39.5474%	38.5025%	-1.0449%	3,474,704	1,374,155	1,337,848	(36,307)	(33,234)	(28,934)	(2,070)	(2,230)	(3,072)	(2,726)	(346)
200068	Finance & Treasury - Corporate Governance	Assets/Revenue/No. of Employees (Corp Gov)	39.5474%	38.5025%	-1.0449%	2,010,949	795,278	774,266	(21,012)	(19,234)	(16,746)	(1,198)	(1,291)	(1,778)	(1,578)	(200)
200069	Risk Management - Corporate Governance	Assets/Revenue/No. of Employees (Corp Gov)	39.5474%	38.5025%	-1.0449%	587,181	232,215	226,079	(6,136)	(5,617)	(4,890)	(350)	(377)	(519)	(461)	(58)
200070	Corporate Strategy & Business Development - Corporate Governance	Assets/Revenue/No. of Employees (Corp Gov)	39.5474%	38.5025%	-1.0449%	3,436,756	1,359,148	1,323,237	(35,911)	(32,872)	(28,619)	(2,047)	(2,206)	(3,039)	(2,697)	(342)
200071	Legal - Corporate Governance	Assets/Revenue/No. of Employees (Corp Gov)	39.5474%	38.5025%	-1.0449%	12,976,846	5,132,005	4,996,410	(135,595)	(124,120)	(108,062)	(7,730)	(8,329)	(11,475)	(10,184)	(1,291)
200072	Communications - Corporate Governance	Assets/Revenue/No. of Employees (Corp Gov)	39.5474%	38.5025%	-1.0449%	4,789,478	1,894,114	1,844,069	(50,045)	(45,810)	(39,883)	(2,853)	(3,074)	(4,235)	(3,759)	(476)
200073	Human Resources - Corporate Governance	Assets/Revenue/No. of Employees (Corp Gov)	39.5474%	38.5025%	-1.0449%	8,366,115	3,308,581	3,221,163	(87,418)	(80,020)	(69,667)	(4,983)	(5,370)	(7,398)	(6,566)	(832)
200074	Corporate Systems	Assets/Revenue/No. of Employees (Corp Gov)	39.5474%	38.5025%	-1.0449%	31,687,723	12,531,671	12,200,566	(331,105)	(303,085)	(263,872)	(18,875)	(20,338)	(28,019)	(24,867)	(3,152)
200075	Board of Directors - Corporate Governance	Asset/Revenue/Number of Employees	39.5474%	38.5025%	-1.0449%	4,364,910	1,726,208	1,680,599	(45,609)	(41,750)	(36,348)	(2,600)	(2,802)	(3,860)	(3,426)	(434)
200076	Xcel Foundation	Assets/Revenue/No. of Employees (Corp Gov)	39.6459%	38.6056%	-1.0403%	5,022,875	1,991,364	1,939,111	(52,253)	(47,831)	(41,643)	(2,979)	(3,210)	(4,422)	(3,925)	(497)
200077	Branding	Assets/Revenue/No. of Employees (Corp Gov)	39.6459%	38.6055%	-1.0404%	9,122,457	3,616,680	3,521,770	(94,910)	(86,878)	(75,638)	(5,410)	(5,830)	(8,032)	(7,128)	(904)
200078	Governmental Affairs	Assets/Revenue/No. of Employees	39.6757%	38.6356%	-1.0401%	3,444,721	1,366,717	1,330,889	(35,828)	(32,796)	(28,553)	(2,042)	(2,201)	(3,032)	(2,691)	(341)
200079	Federal Lobbying	Assets/Revenue/No. of Employees	39.6757%	38.6356%	-1.0401%	832,378	330,252	321,594	(8,658)	(7,925)	(6,900)	(494)	(532)	(733)	(651)	(82)
200080	Capital Asset Accounting	Assets/Revenue/No. of Employees(Unique Iteration of method 1)	44.3195%	43.2479%	-1.0716%	1,020,116	452,110	441,179	(10,931)	(10,006)	(8,711)	(623)	(671)	(925)	(821)	(104)
200081	Accounting, Reporting, & Taxes	Assets/Revenue/No. of Employees	44.4272%	43.3596%	-1.0676%	87,374	38,818	37,885	(933)	(854)	(744)	(53)	(57)	(79)	(70)	(9)
200082	Audit Services	Assets/Revenue/No. of Employees	44.4272%	43.3596%	-1.0676%	-	-	-	-	-	-	-	-	-	-	-
200083	Finance & Treasury	Asset/Revenue/Number of Employees	44.4272%	43.3596%	-1.0676%	-	-	-	-	-	-	-	-	-	-	-
200084	Risk Management	Asset/Revenue/Number of Employees	44.4272%	43.3596%	-1.0676%	-	-	-	-	-	-	-	-	-	-	-
200086	Legal	Assets/Revenue/No. of Employees	44.4272%	43.3596%	-1.0676%	645,658	286,848	279,955	(6,893)	(6,309)	(5,493)	(393)	(423)	(583)	(517)	(66)
200087	Accounting - OpCo's	Assets/Revenue/No. of Employees	44.4391%	43.3716%	-1.0675%	11,390,569	5,061,866	4,940,272	(121,594)	(111,304)	(96,904)	(6,932)	(7,469)	(10,290)	(9,132)	(1,158)
200088	Accounting, Reporting, Tax, Audit Services - OpCo's Electric	Assets/Revenue/No. of Employees	44.4391%	43.3716%	-1.0675%	5,488,423	2,439,006	2,380,417	(58,589)	(53,631)	(46,692)	(3,340)	(3,599)	(4,958)	(4,400)	(558)
200089	Audit Services - OpCo's	Assets/Revenue/No. of Employees	44.4391%	43.3716%	-1.0675%	37,008	16,446	16,051	(395)	(362)	(315)	(23)	(24)	(33)	(29)	(4)
200090	Risk Management - OpCo's	Assets/Revenue/No. of Employees	44.4391%	43.3716%	-1.0675%	3,167,741	1,407,716	1,373,900	(33,816)	(30,954)	(26,949)	(1,928)	(2,077)	(2,862)	(2,540)	(322)
200091	Captive Insurance - OpCo's	Assets/Revenue/No. of Employees	44.4391%	43.3716%	-1.0675%	10,563,647	4,694,390	4,581,623	(112,767)	(103,224)	(89,869)	(6,428)	(6,927)	(9,543)	(8,469)	(1,074)
200092	Corporate Strategy & Business Development OpCo's	Assets/Revenue/No. of Employees	44.4391%	43.3716%	-1.0675%	4,309,971	1,915,312	1,869,303	(46,009)	(42,116)	(36,667)	(2,623)	(2,826)	(3,893)	(3,455)	(438)
200093	Legal - OpCo's	Assets/Revenue/No. of Employees	44.4391%	43.3716%	-1.0675%	-	-	-	-	-	-	-	-	-	-	-
200094	Supply Chain	Assets/Revenue/No. of Employees	44.4391%	43.3716%	-1.0675%	-	-	-	-	-	-	-	-	-	-	-
200095	Energy Supply Asset Management	Assets/Revenue/No. of Employees	44.4391%	43.3716%	-1.0675%	-	-	-	-	-	-	-	-	-	-	-
200096	Energy Markets - Business Services	Assets/Revenue/No. of Employees	44.4391%	43.3716%	-1.0675%	5,403,824	2,401,411	2,343,725	(57,686)	(52,804)	(45,972)	(3,288)	(3,543)	(4,882)	(4,333)	(549)
200097	Accounting and Finance Software Applications Maintenance	Asset/Revenue/Number of Employees	44.4391%	43.3716%	-1.0675%	570,127	253,359	247,273	(6,086)	(5,571)	(4,850)	(347)	(374)	(515)	(457)	(58)
200098	Transm Elec FERC 566	Assets/Revenue/No. of Employees	44.4391%	43.3716%	-1.0675%	748,937	332,821	324,826	(7,995)	(7,318)	(6,371)	(456)	(491)	(677)	(601)	(76)
200099	Elec Dist FERC 588	Assets/Revenue/No. of Employees	44.4391%	43.3716%	-1.0675%	-	-	-	-	-	-	-	-	-	-	-
200100	Audit Services - OpCo's - Gas	Assets/Revenue/No. of Employees	52.0411%	50.8728%	-1.1683%	18,504	9,630	9,414	(216)	(197)	(172)	(12)	(13)	(18)	(16)	(2)
200101	Legal - OpCo's - Gas	Assets/Revenue/No. of Employees	52.0411%	50.8728%	-1.1683%	600,000	312,247	305,237	(7,010)	(6,416)	(5,586)	(400)	(431)	(593)	(526)	(67)
200102	Gas Dist FERC 880	Assets/Revenue/No. of Employees	52.0411%	50.8728%	-1.1683%	94,296	49,073	47,971	(1,102)	(1,008)	(878)	(63)	(68)	(93)	(83)	(10)
200105	Accounting, Reporting, Tax - NSPM & NSPW	Assets/Revenue/No. of Employees	86.4582%	85.8975%	-0.5607%	334,071	288,832	286,959	(1,873)	(1,715)	(1,493)	(107)	(115)	(159)	(141)	(18)
200106	Accounting, Reporting, Tax - NSPM & NSPW Electric	Assets/Revenue/No. of Employees	86.4582%	85.8975%	-0.5607%	233,533	201,909	200,599	(1,310)	(1,199)	(1,044)	(75)	(80)	(111)	(99)	(12)
200107	Legal - NSPM & NSPW	Assets/Revenue/No. of Employees	86.4582%	85.8975%	-0.5607%	184,703	159,691	158,655	(1,036)	(948)	(825)	(59)	(64)	(88)	(78)	(10)
200111	EAI (Enterprise Application Integration)	Average of a Select Set of Software Allocators	39.6838%	39.0822%	-0.6016%	101,138,729	40,135,691	39,527,240	(608,451)	(556,961)	(484,902)	(34,685)	(37,373)	(51,490)	(45,698)	(5,792)
200112	Mainframe Charges From IBM	Average of a Select Set of Software Allocators	28.1294%	27.0910%	-1.0384%	5,824,046	1,638,269	1,577,792	(60,477)	(55,359)	(48,197)	(3,448)	(3,715)	(5,118)	(4,542)	(576)
200115	Miscellaneous Applications	Average of All Software Percentages	36.3060%	35.9329%	-0.3731%	32,147,613	11,671,512	11,551,569	(119,943)	(109,793)	(95,588)	(6,837)	(7,367)	(10,150)	(9,008)	(1,142)
200149	CES (Customer & Enterprise Solutions)	Number of Computers/Number of Customers/Number of Employees	45.2706%	44.2047%	-1.0659%	2,101,690	951,448	929,046	(22,402)	(20,506)	(17,853)	(1,277)	(1,376)	(1,896)	(1,683)	(213)
200163	Employee Communications	No. Of Employees	48.7360%	45.6208%	-3.1152%	797,903	388,866	364,010	(24,856)	(22,752)	(19,808)	(1,417)	(1,527)	(2,103)	(1,866)	(237)
200164	Payroll	No. Of Employees	48.7360%	45.6208%	-3.1152%	1,692,471	824,843	772,119	(52,724)	(48,262)	(42,018)	(3,006)	(3,238)	(4,462)	(3,960)	(502)
200165	Employee Management Systems	No. Of Employees	48.7360%	45.6208%	-3.1152%	8,595,364	4,189,037	3,921,274	(267,763)	(245,103)	(213,392)	(15,264)	(16,447)	(22,659)	(20,110)	(2,549)
200166	Human Resources (Diversity/Safety/Employee Relations)	No. Of Employees	48.8220%	45.6242%	-3.1978%	22,341,960	10,907,791	10,193,340	(714,451)	(653,992)	(569,380)	(40,728)	(43,884)	(60,460)	(53,659)	(6,801)
200167	e-Business	No. Of Employees	48.8220%	45.6242%	-3.1978%	193,518	94,480	88,291	(6,189)	(5,665)	(4,932)	(353)	(380)	(524)	(465)	(59)
200805	Legal - OpCo's - Electric	Assets/Revenue/No. of Employees	44.4391%	43.3716%	-1.0675%	-	-	-	-	-	-	-	-	-	-	-
200806	Legal - NSPM & NSPW Electric	Assets/Revenue/No. of Employees	86.4582%	85.8975%	-0.5607%	-	-	-	-	-	-	-	-	-	-	-
							NSPM Total Company Amount	NSPM Total Company Revised Amount	NSPM Test Year Impact 2020 Budget							
							$ 163,835,630	$ 159,562,332	$ (4,273,298)	$ (3,911,670)	**$ (3,405,585)**	$ (243,607)	$ (262,483)	$ (361,626)	$ (320,945)	$ (40,681)

Minnesota Jurisdiction Electric Long Term Incentive Adjustment	$	103,904
Minnesota Jurisdiction Electric Payroll Tax Adjustment		(32,983)
Total Minnesota Jurisdiction Electric Adjustment	**$**	**(3,334,664)**

THIS FILING IS		
Item 1: ☒ An Initial (Original) Submission	OR ☐	Resubmission No. ____

Form 60 Approved
OMB No. 1902-0215
Expires 05/31/2019

FERC FINANCIAL REPORT
FERC FORM No. 60: Annual Report of Centralized Service Companies

This report is mandatory under the Public Utility Holding Company Act of 2005, Section 1270, Section 309 of the Federal Power Act and 18 C.F.R. § 366.23. Failure to report may result in criminal fines, civil penalties, and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider this report to be of a confidential nature.

Exact Legal Name of Respondent (Company)	Year of Report
Xcel Energy Services Inc.	Dec 31, 2018

GENERAL INSTRUCTIONS FOR FILING FERC FORM NO. 60

I. Purpose

Form No. 60 is an annual regulatory support requirement under 18 CFR 369.1for centralized service companies. The report is designed to collect financial information from centralized service companies subject to the jurisdiction of the Federal Energy Regulatory Commission. The report is considered to be a non-confidential public use form.

II. Who Must Submit

Unless the holding company system is exempted or granted a waiver by Commission rule or order pursuant to §§ 18 CFR 366.3 and 366.4 of this chapter, every centralized service company (see § 367.2) in a holding company system must prepare and file electronically with the Commission the FERC Form No. 60 then in effect pursuant to the General Instructions set out in this form.

III. How to Submit

Submit FERC Form No. 60 electronically through the Form No. 60 Submission Software. Retain one copy of each report for your files. For any resubmissions, submit the filing using the Form No. 60 Submission Software including a justification. Respondents must submit the Corporate Officer Certification electronically.

IV. When to Submit

Submit FERC Form No. 60 according to the filing date contained § 18 CFR 369.1 of the Commission's regulations.

V. Preparation

Prepare this report in conformity with the Uniform System of Accounts (18 CFR 367) (USof A). Interpret all accounting words and phrases in accordance with the USof A.

VI. Time Period

This report covers the entire calendar year.

VII. Whole Dollar Usage

Enter in whole numbers (dollars) only, except where otherwise noted. The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's amounts.

VIII. Accurateness

Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IX. Applicability

For any page(s) that is not applicable to the respondent, enter "NONE," or "Not Applicable" in column (c) on the List of Schedules, page 2.

X. Date Format

Enter the month, day, and year for all dates. Use customary abbreviations. The "Resubmission Date" included in the header of each page is to be completed only for resubmissions (see III. above).

XI. Number Format

Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by use of a minus sign.

XII. Required Entries

Do not make references to reports of previous years or to other reports instead of required entries, except as specifically authorized.

XIII. Prior Year References

Wherever (schedule) pages refer to figures from a previous year, the figures reported must be based upon those shown by the report of the previous year, or an appropriate explanation given as to why the different figures were used.

XIV. Where to Send Comments on Public Reporting Burden

The public reporting burden for the Form No. 60 collection of information is estimated to average 75 hours per response, including

- the time for reviewing instructions, searching existing data sources,
- gathering and maintaining the data-needed, and
- completing and reviewing the collection of information.

Send comments regarding these burden estimates or any aspect of this collection of information, including suggestions for reducing burden, to:

Federal Energy Regulatory Commission, (Attention: Information Clearance Officer, CIO),
888 First Street NE,
Washington, DC 20426
or by email to DataClearance@ferc.gov

And to:

Office of Information and Regulatory Affairs,
Office of Management and Budget, Washington, DC 20503 (Attention: Desk Office for the Federal Energy Regulatory Commission).
Comments to OMB should be submitted by email to: oira_submission@omb.eop.gov

No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. 3512(a)).

DEFINITIONS
I. Respondent -- The person, corporation, or other legal entity in whose behalf the report is made.

FERC FORM NO. 60
ANNUAL REPORT FOR SERVICE COMPANIES

IDENTIFICATION

01 Exact Legal Name of Respondent Xcel Energy Services Inc.	02 Year of Report Dec 31, 2018
03 Previous Name (If name changed during the year)	04 Date of Name Change / /
05 Address of Principal Office at End of Year (Street, City, State, Zip Code) 414 Nicollet Mall, Minneapolis, MN 55401	06 Name of Contact Person Jeffrey S. Savage
07 Title of Contact Person Senior Vice President, Controller	08 Address of Contact Person 414 Nicollet Mall, Minneapolis, MN 55401
09 Telephone Number of Contact Person (612) 330-5658	10 E-mail Address of Contact Person Jeffrey.S.Savage@xcelenergy.com
11 This Report is: (1) [X] An Original (2) [ ] A Resubmission	12 Resubmission Date (Month, Day, Year) / /
13 Date of Incorporation 04/02/1997	14 If Not Incorporated, Date of Organization / /
15 State or Sovereign Power Under Which Incorporated or Organized DELAWARE	
16 Name of Principal Holding Company Under Which Reporting Company is Organized: Xcel Energy, Inc.	

CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

17 Name of Signing Officer Jeffrey S. Savage	19 Signature of Signing Officer Jeffrey S. Savage	20 Date Signed (Month, Day, Year) 04/29/2019
18 Title of Signing Officer Senior Vice President, Controller		

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

List of Schedules and Accounts

1. Enter in Column (c) the terms “None” or “Not Applicable” as appropriate, where no information or amounts have been reported for certain pages.

Line No.	Description (a)	Page Reference (b)	Remarks (c)
1	Schedule I - Comparative Balance Sheet	101-102	
2	Schedule II - Service Company Property	103	None
3	Schedule III - Accumulated Provision for Depreciation and Amortization of Service Company Property	104	None
4	Schedule IV - Investments	105	
5	Schedule V - Accounts Receivable from Associate Companies	106	
6	Schedule VI - Fuel Stock Expenses Undistributed	107	None
7	Schedule VII - Stores Expense Undistributed	108	None
8	Schedule VIII - Miscellaneous Current and Accrued Assets	109	None
9	Schedule IX - Miscellaneous Deferred Debits	110	
10	Schedule X - Research, Development, or Demonstration Expenditures	111	None
11	Schedule XI - Proprietary Capital	201	
12	Schedule XII - Long-Term Debt	202	None
13	Schedule XIII - Current and Accrued Liabilities	203	
14	Schedule XIV - Notes to Financial Statements	204	
15	Schedule XV - Comparative Income Statement	301-302	
16	Schedule XVI - Analysis of Charges for Service - Associate and Nonassociate Companies	303-306	
17	Schedule XVII - Analysis of Billing – Associate Companies (Account 457)	307	
18	Schedule XVIII – Analysis of Billing – Non-Associate Companies (Account 458)	308	None
21	Schedule XIX - Miscellaneous General Expenses - Account 930.2	307	
23	Schedule XX - Organization Chart	401	
24	Schedule XXI - Methods of Allocation	402	

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule I - Comparative Balance Sheet

1. Give balance sheet of the Company as of December 31 of the current and prior year.

Line No.	Account Number (a)	Description (b)	Reference Page No. (c)	As of Dec 31 Current (d)	As of Dec 31 Prior (e)
1		**Service Company Property**			
2	101	Service Company Property	103		
3	101.1	Property Under Capital Leases	103		
4	106	Completed Construction Not Classified			
5	107	Construction Work In Progress	103		
6		Total Property (Total Of Lines 2-5)			
7	108	Less: Accumulated Provision for Depreciation of Service Company Property	104		
8	111	Less: Accumulated Provision for Amortization of Service Company Property			
9		Net Service Company Property (Total of Lines 6-8)			
10		**Investments**			
11	123	Investment In Associate Companies	105		
12	124	Other Investments	105	58,846,927	52,458,124
13	128	Other Special Funds	105		
14		Total Investments (Total of Lines 11-13)		58,846,927	52,458,124
15		**Current And Accrued Assets**			
16	131	Cash			
17	134	Other Special Deposits			
18	135	Working Funds			
19	136	Temporary Cash Investments		2,432,621	783,617
20	141	Notes Receivable			
21	142	Customer Accounts Receivable			
22	143	Accounts Receivable		4,010,102	4,378,617
23	144	Less: Accumulated Provision for Uncollectible Accounts			
24	146	Accounts Receivable From Associate Companies	106	126,469,284	162,568,086
25	152	Fuel Stock Expenses Undistributed	107		
26	154	Materials And Supplies			
27	163	Stores Expense Undistributed	108		
28	165	Prepayments		75,406,515	65,903,870
29	171	Interest And Dividends Receivable		97,268	
30	172	Rents Receivable			
31	173	Accrued Revenues			
32	174	Miscellaneous Current and Accrued Assets			
33	175	Derivative Instrument Assets	109		
34	176	Derivative Instrument Assets – Hedges			
35		Total Current and Accrued Assets (Total of Lines 16-34)		208,415,790	233,634,190
36		**Deferred Debits**			
37	181	Unamortized Debt Expense			
38	182.3	Other Regulatory Assets			
39	183	Preliminary Survey And Investigation Charges			
40	184	Clearing Accounts			
41	185	Temporary Facilities			
42	186	Miscellaneous Deferred Debits		226,041,779	236,892,085
43	188	Research, Development, or Demonstration Expenditures	110		
44	189	Unamortized loss on reacquired debt	111		
45	190	Accumulated Deferred Income Taxes		49,641,056	46,059,841
46		Total Deferred Debits (Total of Lines 37-45)		275,682,835	282,951,926
47		TOTAL ASSETS AND OTHER DEBITS (TOTAL OF LINES 9, 14, 35 and 46)		542,945,552	569,044,240

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule I - Comparative Balance Sheet (continued)

Line No.	Account Number (a)	Description (b)	Reference Page No. (c)	As of Dec 31 Current (d)	As of Dec 31 Prior (e)
48		**Proprietary Capital**			
49	201	Common Stock Issued	201	10	10
50	204	Preferred Stock Issued	201		
51	211	Miscellaneous Paid-In-Capital	201	(309,953)	(309,475)
52	215	Appropriated Retained Earnings	201		
53	216	Unappropriated Retained Earnings	201	2,680,063	(1)
54	219	Accumulated Other Comprehensive Income	201	(12,846,996)	(12,465,627)
55		Total Proprietary Capital (Total of Lines 49-54)		(10,476,876)	(12,775,093)
56		**Long-Term Debt**			
57	223	Advances From Associate Companies	202		
58	224	Other Long-Term Debt	202		
59	225	Unamortized Premium on Long-Term Debt			
60	226	Less: Unamortized Discount on Long-Term Debt-Debit			
61		Total Long-Term Debt (Total of Lines 57-60)			
62		Other Non-current Liabilities			
63	227	Obligations Under Capital Leases-Non-current			
64	228.2	Accumulated Provision for Injuries and Damages			
65	228.3	Accumulated Provision For Pensions and Benefits		181,887,055	191,440,214
66	230	Asset Retirement Obligations			
67		Total Other Non-current Liabilities (Total of Lines 63-66)		181,887,055	191,440,214
68		**Current and Accrued Liabilities**			
69	231	Notes Payable			
70	232	Accounts Payable		156,260,710	179,090,485
71	233	Notes Payable to Associate Companies	203	94,700,000	93,700,000
72	234	Accounts Payable to Associate Companies	203		
73	236	Taxes Accrued		20,490,682	24,526,997
74	237	Interest Accrued		53,659	
75	241	Tax Collections Payable		2,905,742	2,926,853
76	242	Miscellaneous Current and Accrued Liabilities	203	5,015,000	4,138,000
77	243	Obligations Under Capital Leases – Current			
78	244	Derivative Instrument Liabilities			
79	245	Derivative Instrument Liabilities – Hedges			
80		Total Current and Accrued Liabilities (Total of Lines 69-79)		279,425,793	304,382,335
81		**Deferred Credits**			
82	253	Other Deferred Credits		70,753,194	63,933,736
83	254	Other Regulatory Liabilities			
84	255	Accumulated Deferred Investment Tax Credits			
85	257	Unamortized Gain on Reacquired Debt			
86	282	Accumulated deferred income taxes-Other property		1,843,292	1,445,517
87	283	Accumulated deferred income taxes-Other		19,513,094	20,617,531
88		Total Deferred Credits (Total of Lines 82-87)		92,109,580	85,996,784
89		**TOTAL LIABILITIES AND PROPRIETARY CAPITAL (TOTAL OF LINES 55, 61, 67, 80, AND 88)**		542,945,552	569,044,240

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule II - Service Company Property

1. Provide an explanation of Other Changes recorded in Column (f) considered material in a footnote.
2. Describe each construction work in progress on lines 18 through 30 in Column (b).

Line No.	Acct # (a)	Title of Account (b)	Balance at Beginning of Year (c)	Additions (d)	Retirements or Sales (e)	Other Changes (f)	Balance at End of Year (g)
1	301	Organization					
2	303	Miscellaneous Intangible Plant					
3	306	Leasehold Improvements					
4	389	Land and Land Rights					
5	390	Structures and Improvements					
6	391	Office Furniture and Equipment					
7	392	Transportation Equipment					
8	393	Stores equipment					
9	394	Tools, Shop and Garage Equipment					
10	395	Laboratory Equipment					
11	396	Power Operated Equipment					
12	397	Communications Equipment					
13	398	Miscellaneous Equipment					
14	399	Other Tangible Property					
15	399.1	Asset Retirement Costs					
16		**Total Service Company Property (Total of Lines 1-15)**					
17	107	**Construction Work in Progress:**					
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31		**Total Account 107 (Total of Lines 18-30)**					
32		**Total (Lines 16 and Line 31)**					

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule III – Accumulated Provision for Depreciation and Amortization of Service Company Property

1. Provide an explanation of Other Charges in Column (f) considered material in a footnote.

Line No.	Account Number (a)	Description (b)	Balance at Beginning of Year (c)	Additions Charged To Account 403-403.1 404-405 (d)	Retirements (e)	Other Changes Additions (Deductions) (f)	Balance at Close of Year (g)
1	301	Organization					
2	303	Miscellaneous Intangible Plant					
3	306	Leasehold Improvements					
4	389	Land and Land Rights					
5	390	Structures and Improvements					
6	391	Office Furniture and Equipment					
7	392	Transportation Equipment					
8	393	Stores equipment					
9	394	Tools, Shop and Garage Equipment					
10	395	Laboratory Equipment					
11	396	Power Operated Equipment					
12	397	Communications Equipment					
13	398	Miscellaneous Equipment					
14	399	Other Tangible Property					
15	399.1	Asset Retirement Costs					
16		**Total**					

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule IV – Investments

1. For other investments (Account 124) and other special funds (Account128), in a footnote state each investment separately, with description including the name of issuing company, number of shares held or principal investment amount.
2. For temporary cash investments (Account 136), list each investment separately in a footnote.
3. Investments less than $50,000 may be grouped, showing the number of items in each group.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	123	Investment In Associate Companies		
2	124	Other Investments	52,458,124	58,846,928
3	128	Other Special Funds		
4	136	Temporary Cash Investments	783,617	2,432,621
5		(Total of Lines 1-4)	53,241,741	61,279,549

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
Xcel Energy Services Inc.	(1) X An Original (2) __ A Resubmission	/ /	2018

FOOTNOTE DATA

Schedule Page: 105 Line No.: 2 Column: d

FERC Account 124-Other Investments:

Funding vehicles for key man insurance and deferred compensation obligations.

2018	Pacific Life Insurance Co.	Security Life Insurance	Prudential Insurance Co.	Rabbi Trust	Hartford Insurance Co.	Total
Officer Survivor Benefit (OSB) Cash Surrender Value (CSV)	-	-	-	-	530,560	$530,560
Premiums	210,200	48,569	90,913	-	-	$349,682
CSV	10,780,614	460,129	903,939	50,567,552	-	$62,712,234
Loans	(4,432,682)	(312,867)	-	-	-	($4,745,549)
Total	$6,558,132	$195,831	$994,852	$50,567,552	$530,560	$58,846,927

Schedule Page: 105 Line No.: 4 Column: d

FERC Account 136-Temporary Cash Investments:

The full amount represents December 31, 2018 excess cash balance which was held in a temporary cash investment.

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule V – Accounts Receivable from Associate Companies

1. List the accounts receivable from each associate company.
2. If the service company has provided accommodation or convenience payments for associate companies, provide in a separate footnote a listing of total payments for each associate company.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	146	**Accounts Receivable From Associate Companies**		
2		**Associate Company:**		
3		Northern States Power Company, a Minnesota corporation (NSP-Minnesota)	71,367,900	52,743,959
4		Public Service Company of Colorado, a Colorado corporation (PSCo)	58,835,751	45,830,128
5		Southwestern Public Service Company, a New Mexico corporation (SPS)	22,298,269	19,178,589
6		Northern States Power Company, a Wisconsin corporation (NSP-Wisconsin)	11,728,758	9,017,756
7		e-prime, Inc.	24,536	117,257
8		Nicollet Projects I, LLC	(867,394)	82,660
9		Capital Services, LLC	121,230	57,508
10		Eloigne Company	33,651	41,491
11		Xcel Energy WYCO, Inc.	271,037	41,014
12		Quixx Corporation	367	31,258
13		Xcel Energy Ventures, Inc.	14,470	8,453
14		WestGas Interstate, Inc.	1,607	6,022
15		Chippewa and Flambeau Improvement Company	4,527	5,367
16		1480 Welton, Inc.	(187)	4,311
17		Xcel Energy Performance Contracting, Inc.	467	3,896
18		Xcel Energy Wholesale Group, Inc.	6,753	3,660
19		Seren Innovations, Inc.	3,176	2,938
20		Energy Impact Fund Investments, Inc.	672	2,687
21		PSR Investments, Inc.	2,816	2,491
22		Clearwater Investments, Inc.	1,057	2,141
23		Xcel Energy Transmission Development Company, LLC	2,702	1,395
24		Xcel Energy Transmission Holding Company, LLC	4,853	1,299
25		Xcel Energy Ventures Holdings, Inc.	7,863	1,098
26		Xcel Energy Retail Holdings, Inc.	1,493	1,040
27		Xcel Energy Southwest Transmission Company, LLC	(55)	830
28		Xcel Energy Markets Holdings, Inc.	958	810
29		Xcel Energy West Transmission Company, LLC	773	744
30		Xcel Energy International, Inc.	849	731
31		Xcel Energy Communications Group, Inc.	1,162	724
32		Nicollet Holdings Company	624	718
33		Reddy Kilowatt Corporation	602	322
34		Quixxlin Corporation		300
35		NSP Lands, Inc.	84	263
36		United Power & Land Company	380	138
37		Xcel Energy, Inc.	(1,303,665)	(724,714)
38				0
39				
40	**Total**		**162,568,086**	**126,469,284**

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
Xcel Energy Services Inc.	(1) X An Original (2) __ A Resubmission	/ /	2018

FOOTNOTE DATA

Schedule Page: 106 Line No.: 37 Column: d

Xcel Energy Inc.:

This credit balance represents unsettled payments for the 401(k) and restricted stock units. The offsetting equity account for these items are recorded on Xcel Energy Inc. (the Holding Company). The Service Company debits an expense account and credits an intercompany A/R with the Holding Company. The corresponding entry on the Holding Company is a debit to an intercompany A/R with the Service Company and a credit to an equity account.

Schedule Page: 106 Line No.: 38 Column: d

2018 CONVENIENCE PAYMENTS

PSCo	$116,272,627
NSP-Minnesota	93,539,521
SPS	32,286,719
NSP-Wisconsin	15,440,423
Xcel Energy, Inc.	4,443,124
e-prime, Inc.	794,242
Nicollet Projects I, LLC	337,780
Xcel Energy Transmission Development Company	177,857
Quixx Corporation	50,799
Capital Services, LLC	13,245
Chippewa and Flambeau improvement Company	7,866
Xcel Energy Performance Contracting, Inc.	5,797
Xcel Energy Ventures Holdings	360
Seren Innovations, Inc.	285
NSP Lands, Inc.	24
	$263,370,669

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule VI – Fuel Stock Expenses Undistributed

1. List the amount of labor in Column (c) and expenses in Column (d) incurred with respect to fuel stock expenses during the year and indicate amount attributable to each associate company.
2. In a separate footnote, describe in a narrative the fuel functions performed by the service company.

Line No.	Account Number (a)	Title of Account (b)	Labor (c)	Expenses (d)	Total (e)
1	152	Fuel Stock Expenses Undistributed			
2		Associate Company:			
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
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27					
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30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	**Total**				

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule VII – Stores Expense Undistributed

1. List the amount of labor in Column (c) and expenses in Column (d) incurred with respect to stores expense during the year and indicate amount attributable to each associate company.

Line No.	Account Number (a)	Title of Account (b)	Labor (c)	Expenses (d)	Total (e)
1	163	Stores Expense Undistributed			
2		Associate Company:			
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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39					
40	**Total**				

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule VIII - Miscellaneous Current and Accrued Assets

1. Provide detail of items in this account. Items less than $50,000 may be grouped, showing the number of items in each group.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	174	**Miscellaneous Current and Accrued Assets**		
2		**Item List:**		
3				
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39				
40	**Total**			

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule IX - Miscellaneous Deferred Debits

1. Provide detail of items in this account. Items less than $50,000 may be grouped, showing the number of items in each group.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	186	**Miscellaneous Deferred Debits**		
2		**Items List:**		
3		Post Retirement Benefits	235,292,085	224,441,779
4		Life Insurance Premium	1,600,000	1,600,000
5		Other Miscellaneous Deferred Debits		
6				
7				
8				
9				
10				
11				
12				
13				
14				
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39				
40	**Total**		**236,892,085**	**226,041,779**

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule X - Research, Development, or Demonstration Expenditures

1. Describe each material research, development, or demonstration project that incurred costs by the service corporation during the year. Items less than $50,000 may be grouped, showing the number of items in each group.

Line No.	Account Number (a)	Title of Account (b)	Amount (c)
1	188	**Research, Development, or Demonstration Expenditures**	
2		**Project List:**	
3			
4			
5			
6			
7			
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39			
40	**Total**		

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule XI - Proprietary Capital

1. For miscellaneous paid-in capital (Account 211) and appropriate retained earnings (Account 215), classify amounts in each account, with a brief explanation, disclosing the general nature of transactions which give rise to the reported amounts.
2. For the unappropriated retained earnings (Account 216), in a footnote, give particulars concerning net income or (loss) during the year, distinguishing between compensation for the use of capital owed or net loss remaining from servicing nonassociates per the General Instructions of the Uniform System of Accounts. For dividends paid during the year in cash or otherwise, provide rate percentages, amount of dividend, date declared and date paid.

Line No.	Account Number (a)	Title of Account (b)	Description (c)	Amount (d)
1	201	Common Stock Issued	Number of Shares Authorized	1,000
2			Par or Stated Value per Share	0.01
3			Outstanding Number of Shares	1,000
4			Close of Period Amount	10
5		Preferred Stock Issued	Number of Shares Authorized	
6			Par or Stated Value per Share	
7			Outstanding Number of Shares	
8			Close of Period Amount	
9	211	Miscellaneous Paid-In Capital		(309,953)
10	215	Appropriated Retained Earnings		
11	219	Accumulated Other Comprehensive Income		(12,846,996)
12	216	Unappropriated Retained Earnings	Balance at Beginning of Year	2,680,063
13			Net Income or (Loss)	
14			Dividend Paid	
15			Balance at Close of Year	2,680,063

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule XII – Long Term Debt

1. For the advances from associate companies (Account 223), describe in a footnote the advances on notes and advances on open accounts. Names of associate companies from which advances were received shall be shown under the class and series of obligation in Column (c).
2. For the deductions in Column (h), please give an explanation in a footnote.
3. For other long-term debt (Account 224), list the name of the creditor company or organization in Column (b).

Line No.	Account Number (a)	Title of Account (b)	Term of Obligation Class & Series of Obligation (c)	Date of Maturity (d)	Interest Rate (e)	Amount Authorized (f)	Balance at Beginning of Year (g)	Additions Deductions (h)	Balance at Close of Year (i)
1	223	Advances from Associate Companies							
2		Associate Company:							
3									
4									
5									
6									
7									
8									
9									
10									
11									
12									
13		TOTAL							
14	224	Other Long-Term Debt							
15		List Creditor:							
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									
26									
27									
28		TOTAL							

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule XIII – Current and Accrued Liabilities

1. Provide the balance of notes and accounts payable to each associate company (Accounts 233 and 234).
2. Give description and amount of miscellaneous current and accrued liabilities (Account 242). Items less than $50,000 may be grouped, showing the number of items in each group.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	233	Notes Payable to Associates Companies	93,700,000	94,700,000
2				
3				
4				
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24	234	Accounts Payable to Associate Companies		
25				
26				
27				
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31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41	242	Miscellaneous Current and Accrued Liabilities	4,138,000	5,015,000
42				
43				
44				
45				
46				
47				
48				
49				
50		(Total)	97,838,000	99,715,000

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
Xcel Energy Services Inc.	(1) X An Original (2) __ A Resubmission	/ /	2018

FOOTNOTE DATA

Schedule Page: 203 Line No.: 1 Column: d

FERC Account 233-Notes Payable to Associate Companies

The 2018 balance represents intercompany borrowings with Xcel Energy, Inc.

Schedule Page: 203 Line No.: 41 Column: d

FERC Account 242-Miscellaneous Current and Accrued Liabilities

The 2018 balance represents the current benefit obligation for a non-qualified pension plan and retiree medical.

Non-qualified pension plan	$4,048,000
Retiree Medical	967,000
Total	$5,015,000

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
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Schedule XIV- Notes to Financial Statements

1. Use the space below for important notes regarding the financial statements or any account thereof.
2. Furnish particulars as to any significant contingent assets or liabilities existing at the end of the year.
3. Furnish particulars as to any significant increase in services rendered or expenses incurred during the year.
4. Furnish particulars as to any amounts recorded in Account 434, Extraordinary Income, or Account 435, Extraordinary Deductions.
5. Notes relating to financial statements shown elsewhere in this report may be indicated here by reference.
6. Describe the annual statement supplied to each associate service company in support of the amount of interest on borrowed capital and compensation for use of capital billed during the calendar year. State the basis for billing of interest to each associate company. If a ratio, describe in detail how ratio is computed. If more than one ratio explain the calculation. Report the amount of interest borrowed and/or compensation for use of capital billed to each associate company.

ANNUAL REPORT OF XCEL ENERGY SERVICES INC.

For the Years Ended December 31, 2018 and 2017

Schedule XIV - NOTES TO FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Business and System of Accounts — Xcel Energy Services Inc. (XES or the Company) is a wholly owned subsidiary of Xcel Energy Inc. (Xcel Energy). XES provides Northern States Power Company, a Minnesota corporation (NSP-Minnesota), Northern States Power Company, a Wisconsin corporation (NSP-Wisconsin), Public Service Company of Colorado (PSCo) and Southwestern Public Service Company (SPS) and other subsidiaries of Xcel Energy with a variety of administrative, management, engineering, construction and corporate support services at cost. XES began operations effective April 2, 1997 doing business as New Century Energy. All of XES' accounting records conform to the Federal Energy Regulatory Commission (FERC) uniform system of accounts or to systems required by various state regulatory commissions, which are the same in all material respects.

Basis of Accounting — The accompanying financial statements were prepared in accordance with the accounting requirements of the FERC as set forth in the Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than Generally Accepted Accounting Principles (GAAP). The following areas represent the significant differences between the Uniform System of Accounts and GAAP:

- Accumulated deferred income taxes are shown as long-term assets and liabilities at their gross amounts in the FERC presentation, in contrast to the GAAP presentation as net long-term assets and liabilities.
- Unrecognized tax benefits are recorded for temporary differences in accounts established for accumulated deferred income taxes in the FERC presentation, in contrast to the GAAP presentation as taxes accrued and noncurrent other liabilities.
- Various expenses such as donations, lobbying, and other non-regulatory expenses are presented as other income and deductions for the FERC presentation and reported as operating expenses for the GAAP presentation.
- Income tax expense is shown as a component of operating expenses in the FERC presentation, in contrast to the GAAP presentation as a below-the-line deduction from operating income.

Subsequent Events **—** Management has evaluated the impact of events occurring after Dec. 31, 2018 up to Feb. 22, 2019, the date Xcel Energy's GAAP financial statements were issued and has updated such evaluation for disclosure purposes through the date of filing this report. These statements contain all necessary adjustments and disclosures resulting from these evaluations.

Use of Estimates — In recording transactions and balances resulting from business operations, XES uses estimates based on the best information available. The recorded estimates are revised when better information becomes available or when actual amounts can be determined. Those revisions can affect operating results.

Benefit Plans and Other Postretirement Benefits — Xcel Energy maintains pension and postretirement benefit plans for eligible employees. Recognizing the cost of providing benefits and measuring the projected benefit obligation of these plans under applicable accounting guidance requires management to make various assumptions and estimates.

Based on the regulatory recovery mechanisms of Xcel Energy's utility subsidiaries, certain unrecognized actuarial gains and losses and unrecognized prior service costs or credits are recorded as regulatory assets and liabilities, rather than other comprehensive income.

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
Xcel Energy Services Inc.	(1) X An Original (2) __ A Resubmission	/ /	2018

Schedule XIV- Notes to Financial Statements

Leases — XES evaluates a variety of contracts for lease classification at inception, including rental arrangements for office space, vehicles and equipment. Contracts determined to contain a lease because of per unit pricing that is other than fixed or market price, terms regarding the use of a particular asset, and other factors are evaluated further to determine if the arrangement is a capital lease.

Income Taxes — The Company's operations are included in the consolidated federal income tax return of Xcel Energy. The allocation of income tax consequences to the Company is calculated under a parent company policy which provides that benefits or liabilities created by the Company, computed on a separate return basis, will be allocated to (and paid to or by) the Company to the extent the benefits are usable or additional liabilities are incurred in Xcel Energy's consolidated tax returns. Deferred taxes are provided on temporary differences between the financial accounting and tax bases of assets and liabilities using the tax rates that are in effect at the balance sheet date (see Note 6).

Cash and Cash Equivalents — XES considers investments in certain instruments with a remaining maturity of three months or less at the time of purchase, to be cash equivalents.
Accounts Receivable **—** Accounts receivable are stated at the actual billed amount.

2. Common Stock

XES has authorized the issuance of common stock.

Common Shares Authorized	Par Value
1,000	$ 0.01

At Dec. 31, 2018 and 2017, all shares of common stock were issued and held by Xcel Energy.

3. Borrowings and Other Financing Instruments

Money Pool **–** Xcel Energy has established a utility money pool arrangement with NSP-Minnesota, PSCo, and SPS. The utility money pool, administered by XES, allows for short-term investments in and borrowings between the participating utility subsidiaries. Xcel Energy may make investments in the participating utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the participating utility subsidiaries to make investments in Xcel Energy.

The Board of Directors has authorized the Company to borrow directly from Xcel Energy. At Dec. 31, intercompany borrowings outstanding and the weighted average interest rate were as follows:

(Amounts in Thousands of Dollars, Except Interest Rates)	Twelve Months Ended Dec. 31, 2018	Twelve Months Ended Dec. 31, 2017
Borrowing limit	$ 300,000	$ 300,000
Intercompany borrowings outstanding at period end	94,700	93,700
Average amount outstanding	144,495	153,632
Maximum amount outstanding	252,500	255,400
Weighted average interest rate, computed on a daily basis	2.46 %	1.38 %
Weighted average interest rate at period end	2.97	1.80

4. Commitments and Contingencies

Leases — XES leases a variety of equipment and facilities used in the normal course of business. Total expenses under operating lease obligations for XES were approximately $23 million and $21 million in 2018 and 2017, respectively.

Future commitments under operating leases are as follows:

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Schedule XIV- Notes to Financial Statements

(Thousands of Dollars)	Total Operating Leases
2019	$ 22,949
2020	22,765
2021	22,563
2022	22,054
2023	21,566
Thereafter	124,130

Technology Agreements — XES has a contract that extends through December 2022 with International Business Machines Corp. (IBM) for information technology services. The contract is cancelable at the XES' option, although XES would be obligated to pay 50 percent of the contract value for early termination. XES capitalized or expensed $81 million, $98 million and $119 million associated with the IBM contract in 2018, 2017 and 2016, respectively.

XES' contract with Accenture for information technology services extends through December 2020. The contract is cancelable at XES' option, although there are financial penalties for early termination. XES capitalized or expensed $46 million, $16 million and $35 million associated with the Accenture contract in 2018, 2017 and 2016, respectively.

Committed minimum payments under these obligations are as follows:

(Millions of Dollars)	IBM Agreement	Accenture Agreement
2019	$ 30	$ 11
2020	16	11
2021	16	-
2022	7	-
2023	-	-
Thereafter	-	-

5. Benefit Plans and Other Postretirement Benefits

Pension and other postretirement disclosures below represent Xcel Energy consolidated information unless specifically identified as being attributable to XES. Consistent with the process for rate recovery of pension and postretirement benefits for its employees, XES accounts for its participation in, and related costs of, pension and other postretirement benefit plans sponsored by Xcel Energy as multiple employer plans. XES is responsible for its share of cash contributions, plan costs and obligations and is entitled to its share of plan assets; accordingly, XES accounts for its pro rata share of these plans, including pension expenses and contributions, resulting in accounting consistent with that of a single employer plan exclusively for XES employees.

The plans invest in various instruments which are disclosed under the accounting guidance for fair value measurements which establishes a hierarchical framework for disclosing the observability of the inputs utilized in measuring fair value. The three levels in the hierarchy and examples of each level are as follows:

Level 1 — Quoted prices are available in active markets for identical assets as of the reporting date. The types of assets included in Level 1 are highly liquid and actively traded instruments with quoted prices.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets included in Level 2 are typically either comparable to actively traded securities or contracts, or priced with models using highly observable inputs.

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Schedule XIV- Notes to Financial Statements

Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets included in Level 3 are those with inputs requiring significant management judgment or estimation.

Pension Benefits

Xcel Energy, which includes XES, has several noncontributory, defined benefit pension plans that cover almost all employees. Generally, benefits are based on a combination of years of service, the employee's average pay and, in some cases, social security benefits. Xcel Energy and XES' policy is to fully fund into an external trust the actuarially determined pension costs recognized for ratemaking and financial reporting purposes, subject to the limitations of applicable employee benefit and tax laws.

In addition to the qualified pension plans, Xcel Energy maintains a supplemental executive retirement plan (SERP) and a nonqualified pension plan. The SERP is maintained for certain executives that were participants in the plan in 2008, when the SERP was closed to new participants. The nonqualified pension plan provides unfunded, nonqualified benefits for compensation that is in excess of the limits applicable to the qualified pension plans. The total obligations of the SERP and nonqualified plan as of Dec. 31, 2018 and 2017 for XES were $23.1 million and $24.9 million, respectively. In 2018 and 2017, XES recognized net benefit cost for financial reporting for the SERP and nonqualified plans of $2.8million and $3.7 million, respectively. Benefits for these unfunded plans are paid out of Xcel Energy's consolidated operating cash flows.

In 2016, Xcel Energy established rabbi trusts to provide partial funding for future distributions of the SERP and its deferred compensation plan, supplemented by Xcel Energy's consolidated operating cash flows as determined necessary. Also in 2016, Xcel Energy amended the deferred compensation plan to provide eligible participants the ability to diversify deferred settlements of equity awards, other than time-based equity awards, into various fund options.

Xcel Energy and XES base their investment-return assumption on expected long-term performance for each of the investment types included in its pension asset portfolio. Xcel Energy and XES consider the historical returns achieved by its asset portfolio over the past 20-year or longer period, as well as the long-term return levels projected and recommended by investment experts. Investment returns were below the assumed levels of 6.87 percent in 2018 and above the assumed levels of 6.87 percent in 2017. Xcel Energy and XES continually review their pension assumptions. In 2019, Xcel Energy and XES will use an investment return assumption of 6.87 percent. The pension cost determination assumes a forecasted mix of investment types over the long-term.

The assets are invested in a portfolio according to Xcel Energy and XES' return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize the necessity of contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the projected allocation of assets to selected asset classes, given the long-term risk, return, and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any particular industry, index, or entity. Market volatility can impact even well-diversified portfolios and significantly affect the return levels achieved by pension assets in any year.

The following table presents the target pension asset allocations for Xcel Energy at Dec. 31 for the upcoming year:

	2018	2017
Domestic and international equity securities	36 %	36 %
Long-duration fixed income and interest rate swap securities	30	27
Short-to-intermediate fixed income securities	17	20
Alternative investments	15	15
Cash	2	2
Total	100 %	100 %

The ongoing investment strategy is based on plan-specific investment recommendations that seek to minimize potential investment and interest rate risk as a plan's funded status increases over time. The investment recommendations result in a greater percentage of long-duration fixed income securities being allocated to specific plans having relatively higher funded status ratios and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios. The aggregate projected asset allocation presented in the table above for the master pension trust results from the plan-specific strategies.

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Schedule XIV- Notes to Financial Statements

Pension Plan Assets

The following tables present, for each of the fair value hierarchy levels, Xcel Energy's pension plan assets that are measured at fair value as of Dec. 31, 2018 and 2017:

	Dec. 31, 2018				
(Millions of Dollars)	Level 1	Level 2	Level 3	Investments Measured at NAV	Total
Cash equivalents	$ 137	$ -	$ -	$ -	$ 137
Commingled funds	914	-	-	987	1,901
Debt securities	-	621	-	-	621
Equity securities	106	-	-	-	106
Other	2	5	-	(30)	(23)
Total	$ 1,159	$ 626	$ -	$ 957	$ 2,742

	Dec. 31, 2017				
(Millions of Dollars)	Level 1	Level 2	Level 3	Investments Measured at NAV	Total
Cash equivalents	$ 196	$ -	$ -	$ -	$ 196
Commingled funds	1,054	-	-	1,075	2,129
Debt securities	-	673	-	-	673
Equity securities	114	-	-	-	114
Other	(29)	4	-	1	(24)
Total	$ 1,335	$ 677	$ -	$ 1,076	$ 3,088

Benefit Obligations — A comparison of the actuarially computed pension benefit obligation and plan assets for Xcel Energy is presented in the following table:

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Schedule XIV- Notes to Financial Statements

(Thousands of Dollars)	2018	2017
Accumulated Benefit Obligation at Dec. 31	$ 3,275,061	$ 3,612,354
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	$ 3,827,650	$ 3,681,618
Service cost	94,357	94,189
Interest cost	133,388	146,809
Plan amendments	-	(12,543)
Actuarial loss (gain)	(226,634)	258,613
Benefit Payments [(a)]	(354,358)	(341,036)
Obligation at Dec. 31	$ 3,474,403	$ 3,827,650

(Thousands of Dollars)	2018	2017
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	$ 3,087,959	$ 2,855,813
Actual return (loss) on plan assets	(141,329)	411,628
Employer contributions	150,000	161,554
Benefit payments	(354,358)	(341,036)
Fair value of plan assets at Dec. 31	$ 2,742,272	$ 3,087,959
Funded Status of Plans at Dec. 31:		
Funded status [(b)]	$ (732,131)	$ (739,691)

[(a)] Amount includes approximately $198 million in 2018 and $174 million in 2017 of lump-sum benefit payments used in the determination of a settlement charge.

[(b)] Amounts are recognized in noncurrent liabilities on Xcel Energy's consolidated balance sheets.

(Thousands of Dollars)	2018	2017
XES Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	$ 232,026	$ 239,618
Prior service cost	(10,292)	(11,277)
Total	$ 221,734	$ 228,341

(Thousands of Dollars)	2018	2017
XES Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Miscellanous deferred debits	$ 212,183	$ 218,116
Accumulated deferred income taxes	2,469	2,652
Net-of-tax accumulated other comprehensive income	7,082	7,573
Total	$ 221,734	$ 228,341
XES accumulated provision for pensions and benefits	$ 136,997	$ 140,602
Measurement date	Dec. 31, 2018	Dec. 31, 2017

	2018	2017
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	4.31 %	3.63 %
Expected average long-term increase in compensation level	3.75	3.75
Mortality table	RP-2014	RP-2014

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
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Schedule XIV- Notes to Financial Statements

Mortality — In 2014, the Society of Actuaries published a new mortality table (RP-2014) and projection scale (MP-2014) that increased the overall life expectancy of males and females. In 2014, Xcel Energy adopted this mortality table, with modifications, based on its population and specific experience. During 2017, a new projection table was released (MP-2017). Xcel Energy evaluated the updated projection table and concluded that the methodology currently in use and adopted in 2016 is consistent with the recently updated 2017 table and continues to be representative of Xcel Energy's population.

Cash Flows — Cash funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the funding requirements of income tax and other pension-related regulations. Required contributions were made in 2016 through 2019 to meet minimum funding requirements. Total voluntary and required pension funding contributions across all four of Xcel Energy's pension plans were as follows:

- $150 million in January 2019;
- $150 million in 2018;
- $162 million in 2017; and
- $125 million in 2016.

For future years, Xcel Energy anticipates contributions will be made as necessary.

Plan Amendments — Xcel Energy amended the Xcel Energy Pension Plan and Xcel Energy Inc. Nonbargaining Pension Plan (South) in 2017 to reduce supplemental benefits for non-bargaining participants as well as to allow the transfer of a portion of nonqualified pension obligations into the qualified plans.

In 2018 and 2017, there were no plan amendments made which affected the projected benefit obligation.

Benefit Costs — The components of Xcel Energy's net periodic pension cost were:

(Thousands of Dollars)	2018	2017
Service cost	$ 94,357	$ 94,189
Interest cost	133,388	146,809
Expected return on plan assets	(208,762)	(209,270)
Amortization of prior service credit	(4,643)	(1,768)
Amortization of net loss	110,798	106,681
Settlement charge	90,705	81,136
Net periodic pension cost	215,843	217,777
Costs not recognized due to effects of regulation	(75,486)	(78,722)
Net benefit cost recognized for financial reporting	$ 140,357	$ 139,055
XES:		
Net periodic pension cost	$ 45,358	$ 49,566

	2018	2017
Significant Assumptions Used to Measure Costs:		
Discount rate	3.63 %	4.13 %
Expected average long-term increase in compensation level	3.75	3.75
Expected average long-term rate of return on assets	6.87	6.87

Pension costs include an expected return impact for the current year that may differ from actual investment performance in the plan. The return assumption used for 2018 pension cost calculations is 6.87 percent. The pension cost calculation uses a market-related valuation of pension assets. Xcel Energy uses a calculated value method to determine the market-related value of the plan assets. The market-related value is determined by adjusting the fair market value of assets at the beginning of the year to reflect the investment gains and losses (the difference between the actual investment return and the expected investment return on the market related value) during each of the previous five years at the rate of 20 percent per year. As these differences between the actual investment returns and the expected investment returns are incorporated into the market-related value, the differences are recognized in pension cost over the expected average remaining years of service for active employees, which was approximately 13 years in 2018.

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Defined Contribution Plans

Xcel Energy, which includes XES, maintains 401(k) and other defined contribution plans that cover substantially all employees. Total expense to these plans was approximately $38 million in 2018 and $37 million in 2017. XES' portion of that expense was approximately $11 million in 2018 and $10 million in 2017.

Postretirement Health Care Benefits

Xcel Energy, which includes XES, has a contributory health and welfare benefit plan that provides health care and death benefits to certain retirees.

Plan Assets — Certain state agencies that regulate Xcel Energy's utility subsidiaries also have issued guidelines related to the funding of postretirement benefit costs. These assets are invested in a manner consistent with the investment strategy for the pension plan.

The following table presents the target postretirement asset allocations for Xcel Energy at Dec. 31 for the upcoming year:

	2018	2017
Domestic and international equity securities	18 %	24 %
Short-to-intermediate fixed income securities	70	60
Alternative investments	8	9
Cash	4	7
Total	100 %	100 %

Xcel Energy and XES bases its investment-return assumption for the postretirement health care fund assets on expected long-term performance for each of the investment types included in its asset portfolio. The assets are invested in a portfolio according to Xcel Energy's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the projected asset allocation given the long-term risk, return, correlation and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any particular industry, index, or entity. Market volatility can impact even well-diversified portfolios and significantly affect the return levels achieved by postretirement health care assets in any year.

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The following tables present, for each of the fair value hierarchy levels, Xcel Energy's postretirement benefit plan assets that are measured at fair value as of Dec. 31, 2018 and 2017:

	Dec. 31, 2018				
(Millions of Dollars)	Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 19	$ -	$ -	$ -	$ 19
Insurance contracts	-	45	-	-	45
Commingled funds	133	-	-	40	173
Debt securities	-	179	-	-	179
Equity securities	-	-	-	-	-
Other	-	1	-	-	1
Total	$ 152	$ 225	$ -	$ 40	$ 417

	Dec. 31, 2017				
(Millions of Dollars)	Level 1	Level 2	Level 3	Investments Measured at NAV	Total
Cash equivalents	$ 29	$ -	$ -	$ -	$ 29
Insurance contracts	-	50	-	-	50
Commingled funds	148	-	-	-	148
Debt securities	-	198	-	-	198
Equity securities	35	-	-		35
Other	-	1	-	-	1
Total	$ 212	$ 249	$ -	$ -	$ 461

There were no assets transferred in or out of Level 3 for the years ended Dec. 31, 2018 and 2017.

Benefit Obligations — A comparison of the actuarially computed benefit obligation and plan assets for Xcel Energy is presented in the following table:

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(Thousands of Dollars)	2018	2017
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	$ 620,931	$ 603,084
Service cost	1,996	1,859
Interest cost	21,663	23,937
Medicare subsidy reimbursements	1,020	1,066
Plan participants' contributions	7,944	7,488
Actuarial loss (gain)	(61,677)	33,286
Benefit payments	(50,162)	(49,789)
Obligation at Dec. 31	$ 541,715	$ 620,931

(Thousands of Dollars)	2018	2017
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	$ 460,602	$ 442,105
Actual return (loss) on plan assets	(12,338)	40,748
Plan participants' contributions	7,944	7,488
Employer contributions	10,932	20,050
Benefit payments	(50,162)	(49,789)
Fair value of plan assets at Dec. 31	$ 416,978	$ 460,602

(Thousands of Dollars)	2018	2017
Funded Status of Plans at Dec. 31:		
Funded status	$ (124,737)	$ (160,329)
Miscellaneous deferred debits	(6,486)	(2,509)
Accumulated provision for pensions and benefits	(118,251)	(157,820)
Net postretirement amounts recognized on balance sheet	$ (124,737)	$ (160,329)

(Thousands of Dollars)	2018	2017
XES Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	$ 15,402	$ 18,828
Prior service credit	(1,606)	(2,163)
Total	$ 13,796	$ 16,665

(Thousands of Dollars)	2018	2017
XES Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Miscellaneous deferred debits	$ 11,476	$ 14,140
Accumulated deferred income taxes	600	653
Net-of-tax accumulated other comprehensive income	1,720	1,872
Total	$ 13,796	$ 16,665
XES accumulated provision for pensions and benefits	$ 26,387	$ 29,807
Measurement date	Dec. 31, 2018	Dec. 31, 2017

	2018	2017
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	4.32 %	3.62 %
Mortality table	RP-2014	RP-2014
Health care costs trend rate - initial: Pre-65	6.50 %	7.00 %
Health care costs trend rate - initial: Post-65	5.35 %	5.50 %

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Beginning with the Dec. 31, 2018 measurement, Xcel Energy Inc. separated its initial medical trend assumption for pre-Medicare (Pre-65) and post-Medicare (Post-65) claims costs in order to reflect different short-term expectations based on recent experience differences. The Post-65 initial medical trend rate was set at 5.3 percent. The Pre-65 initial medical trend rate was set at 6.5 percent. The ultimate trend assumption remained at 4.5 percent for both groups. The period until the ultimate rate is reached is four years. Xcel Energy bases its medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost increases experienced by Xcel Energy's retiree medical plan.

A one-percent change in the assumed health care cost trend rate would have the following effects on Xcel Energy:

(Thousands of Dollars)	One Percentage Point Increase	One Percentage Point Decrease
Accumulated postretirement benefit obligation	$ 49,399	$ (42,213)
Service and interest components	2,526	(2,122)

Cash Flows — The postretirement health care plans have no funding requirements under income tax and other retirement-related regulations other than fulfilling benefit payment obligations, when claims are presented and approved under the plans. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities. Xcel Energy, which includes XES, contributed $11 million during 2018, $20 million during 2017 and $18 million during 2016 and expects to contribute approximately $11 million during 2019.

Plan Amendments — In 2018and 2017, there were no plan amendments made which affected the benefit obligation.

Benefit Costs — The components of Xcel Energy's net periodic postretirement benefit cost were:

(Thousands of Dollars)	2018	2017
Service cost	$ 1,996	$ 1,859
Interest cost	21,663	23,937
Expected return on plan assets	(25,747)	(24,622)
Amortization of prior service credit	(10,629)	(10,686)
Amortization of net loss	7,711	6,689
Net periodic postretirement benefit credit	$ (5,006)	$ (2,823)
XES:		
Net periodic postretirement benefit cost recognized	1,527	1,491

	2018	2017
Significant Assumptions Used to Measure Costs:		
Discount rate	3.62 %	4.13 %
Expected average long-term rate of return on assets	5.80	5.80

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Schedule XIV- Notes to Financial Statements

Projected Benefit Payments

The following table lists Xcel Energy's projected benefit payments for the pension and postretirement benefit plans:

(Thousands of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
2019	$ 280,528	$ 45,493	$ 2,062	$ 43,431
2020	259,549	45,058	2,159	42,899
2021	258,959	44,622	2,270	42,352
2022	260,145	44,115	2,372	41,743
2023	259,345	43,245	2,465	40,780
2024-2028	1,238,409	196,553	13,451	183,102

6. Income Taxes

The components of income tax expense for the years ending Dec. 31 were as follows:

(Thousands of Dollars)	2018	2017
Current federal tax expense	$ 9,518	$ 11,859
Current state tax expense	3,529	3,531
Current change in unrecognized tax expense	5,341	-
Deferred federal tax benefit	(3,963)	7,171
Deferred state tax benefit	(1,122)	(1,271)
Total income tax expense	$ 13,303	$ 21,290

Total income tax expense from operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense. The following reconciles such differences for the years ending Dec. 31:

	2018	2017
Federal statutory rate	21 %	35 %
State income taxes, net of federal income tax benefit	5	4
Increases (decreases) in tax from:		
Resolutions of income tax audit and other	38	-
Tax Reform	-	56
Adjustments attributable to tax returns	13	(1)
Texas margin tax, net of federal tax effect	6	3
Executive officer non-deductible compensation	15	2
Non-deductible business meals	2	1
Insurance fund income	-	(1)
Penalties	-	1
Effective income tax rate	100 %	100 %

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The components of the accumulated deferred income taxes at Dec. 31 were as follows:

(Thousands of Dollars)	2018	2017
Deferred tax liabilities:		
Employee benefits	$ 19,326	$ 20,094
Differences between book and tax bases of property	1,843	1,446
Other	187	523
Total deferred tax liabilities	$ 21,356	$ 22,063
Deferred tax assets:		
Employee benefits	$ 45,158	$ 43,410
Other	4,483	2,650
Total deferred tax assets	$ 49,641	$ 46,060
Net deferred tax asset	$ (28,285)	$ (23,997)

7. Financial Instruments

In June 2016, XES established rabbi trusts to provide partial funding for future distributions of its supplemental executive retirement plan and deferred compensation plan. The following table presents the cost and fair value of the assets held in rabbi trusts at Dec. 31, 2018 and 2017:

	Dec. 31, 2018				
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$ 13	$ 13	$ -	$ -	$ 13
Mutual funds	37	37	-	-	37
Total	$ 50	$ 50	$ -	$ -	$ 50

	Dec. 31, 2017				
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$ 11	$ 11	$ -	$ -	$ 11
Mutual funds	32	34	-	-	34
Total	$ 43	$ 45	$ -	$ -	$ 45

[(a)] Reported as other investments on the balance sheet.

As of Dec. 31, 2018 and 2017, there were no financial instruments for which carrying amount did not equal fair value.

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Schedule XV- Comparative Income Statement

Line No.	Account Number (a)	Title of Account (b)	Current Year (c)	Prior Year (d)
1		**SERVICE COMPANY OPERATING REVENUES**		
2	400	Service Company Operating Revenues	1,365,832,804	1,345,415,785
3		**SERVICE COMPANY OPERATING EXPENSES**		
4	401	Operation Expenses	866,865,817	837,889,409
5	402	Maintenance Expenses	16,627,241	18,141,289
6	403	Depreciation Expenses		
7	403.1	Depreciation Expense for Asset Retirement Costs		
8	404	Amortization of Limited-Term Property		
9	405	Amortization of Other Property		
10	407.3	Regulatory Debits		
11	407.4	Regulatory Credits		
12	408.1	Taxes Other Than Income Taxes, Operating Income	20,113,285	19,878,182
13	409.1	Income Taxes, Operating Income	(13,303,106)	(21,289,997)
14	410.1	Provision for Deferred Income Taxes, Operating Income		
15	411.1	Provision for Deferred Income Taxes – Credit , Operating Income		
16	411.4	Investment Tax Credit, Service Company Property		
17	411.6	Gains from Disposition of Service Company Plant		
18	411.7	Losses from Disposition of Service Company Plant		
19	411.10	Accretion Expense		
20	412	Costs and Expenses of Construction or Other Services	429,194,493	442,130,233
21	416	Costs and Expenses of Merchandising, Jobbing, and Contract Work		
22		TOTAL SERVICE COMPANY OPERATING EXPENSES (Total of Lines 4-21)	1,319,497,730	1,296,749,116
23		NET SERVICE COMPANY OPERATING INCOME (Total of Lines 2 less 22)	46,335,074	48,666,669
24		**OTHER INCOME**		
25	418.1	Equity in Earnings of Subsidiary Companies		
26	419	Interest and Dividend Income	1,727,968	3,424,492
27	419.1	Allowance for Other Funds Used During Construction		
28	421	Miscellaneous Income or Loss		
29	421.1	Gain on Disposition of Property		
30		**TOTAL OTHER INCOME (Total of Lines 25-29)**	1,727,968	3,424,492
31		**OTHER INCOME DEDUCTIONS**		
32	421.2	Loss on Disposition of Property		
33	425	Miscellaneous Amortization		
34	426.1	Donations	13,208,190	2,423,425
35	426.2	Life Insurance	(242,554)	(419,466)
36	426.3	Penalties	174,412	76,076
37	426.4	Expenditures for Certain Civic, Political and Related Activities	2,202,956	4,003,542
38	426.5	Other Deductions	761,086	663,501
39		**TOTAL OTHER INCOME DEDUCTIONS (Total of Lines 32-38)**	16,104,090	6,747,078
40		**TAXES APPLICABLE TO OTHER INCOME AND DEDUCTIONS**		

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Schedule XV- Comparative Income Statement (continued)

Line No.	Account Number (a)	Title of Account (b)	Current Year (c)	Prior Year (d)
41	408.2	Taxes Other Than Income Taxes, Other Income and Deductions	456,634	145,592
42	409.2	Income Taxes, Other Income and Deductions	31,691,071	36,680,480
43	410.2	Provision for Deferred Income Taxes, Other Income and Deductions	(5,084,859)	5,900,374
44	411.2	Provision for Deferred Income Taxes – Credit, Other Income and Deductions		(859)
45	411.5	Investment Tax Credit, Other Income Deductions		
46		**TOTAL TAXES APPLICABLE TO OTHER INCOME AND DEDUCTIONS (Total of Lines 41-45)**	27,062,846	42,725,587
47		**INTEREST CHARGES**		
48	427	Interest on Long-Term Debt		
49	428	Amortization of Debt Discount and Expense		
50	429	(less) Amortization of Premium on Debt- Credit		
51	430	Interest on Debt to Associate Companies	4,882,814	2,498,664
52	431	Other Interest Expense	13,292	119,832
53	432	(less) Allowance for Borrowed Funds Used During Construction-Credit		
54		**TOTAL INTEREST CHARGES (Total of Lines 48-53)**	4,896,106	2,618,496
55		**NET INCOME BEFORE EXTRAORDINARY ITEMS (Total of Lines 23, 30, minus 39, 46, and 54)**		
56		**EXTRAORDINARY ITEMS**		
57	434	Extraordinary Income		
58	435	(less) Extraordinary Deductions		
59		**Net Extraordinary Items (Line 57 less Line 58)**		
60	409.4	(less) Income Taxes, Extraordinary		
61		**Extraordinary Items After Taxes (Line 59 less Line 60)**		
62		**NET INCOME OR LOSS/COST OF SERVICE (Total of Lines 55-61)**		

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FOOTNOTE DATA

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FERC Account 426.2-Life Insurance:

The balance in FERC account 426.2 includes the net premiums less increase in cash surrender value of policies.

Cash surrender value of policies	($347,472)
Premiums	104,918
Total	($242,554)

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Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies

1. Total cost of service will equal for associate and nonassociate companies the total amount billed under their separate analysis of billing schedules.

Line No.	Account Number (a)	Title of Account (b)	Associate Company Direct Cost (c)	Associate Company Indirect Cost (d)	Associate Company Total Cost (e)	Nonassociate Company Direct Cost (f)	Nonassociate Company Indirect Cost (g)	Nonassociate Company Total Cost (h)
1	403-403.1	Depreciation Expense						
2	404-405	Amortization Expense						
3	407.3-407.4	Regulatory Debits/Credits – Net						
4	408.1-408.2	Taxes Other Than Income Taxes	8,079,395	12,490,524	20,569,919			
5	409.1-409.3	Income Taxes	18,387,965		18,387,965			
6	410.1-411.2	Provision for Deferred Taxes	(5,084,859)		(5,084,859)			
7	411.1-411.2	Provision for Deferred Taxes – Credit						
8	411.6	Gain from Disposition of Service Company Plant						
9	411.7	Losses from Disposition of Service Company Plant						
10	411.4-411.5	Investment Tax Credit Adjustment						
11	411.10	Accretion Expense						
12	412	Costs and Expenses of Construction or Other Services	429,194,493		429,194,493			
13	416	Costs and Expenses of Merchandising, Jobbing, and Contract Work for Associated Companies						
14	418	Non-operating Rental Income						
15	418.1	Equity in Earnings of Subsidiary Companies						
16	419	Interest and Dividend Income	1,376,644	351,324	1,727,968			
17	419.1	Allowance for Other Funds Used During Construction						
18	421	Miscellaneous Income or Loss						
19	421.1	Gain on Disposition of Property						
20	421.2	Loss on Disposition Of Property						
21	425	Miscellaneous Amortization						
22	426.1	Donations	201,672	13,006,518	13,208,190			
23	426.2	Life Insurance		(242,554)	(242,554)			
24	426.3	Penalties	173,530	882	174,412			
25	426.4	Expenditures for Certain Civic, Political and Related Activities	398,980	1,803,976	2,202,956			
26	426.5	Other Deductions	197,208	563,878	761,086			
27	427	Interest On Long-Term Debt						
28	428	Amortization of Debt Discount and Expense						
29	429	Amortization of Premium on Debt – Credit						
30	430	Interest on Debt to Associate Companies	4,882,814		4,882,814			
31	431	Other Interest Expense		13,292	13,292			
32	432	Allowance for Borrowed Funds Used During Construction						
33	500-509	Total Steam Power Generation Operation Expenses	31,086,485	7,313,059	38,399,544			
34	510-515	Total Steam Power Generation Maintenance Expenses	10,224,130	904	10,225,034			

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Line No.	Account Number (a)	Title of Account (b)	Associate Company Direct Cost (c)	Associate Company Indirect Cost (d)	Associate Company Total Cost (e)	Nonassociate Company Direct Cost (f)	Nonassociate Company Indirect Cost (g)	Nonassociate Company Total Cost (h)
35	517-525	Total Nuclear Power Generation Operation Expenses	15,791,256		15,791,256			
36	528-532	Total Nuclear Power Generation Maintenance Expenses	541,176		541,176			
37	535-540.1	Total Hydraulic Power Generation Operation Expenses	2,227,084	363,312	2,590,396			
38	541-545.1	Total Hydraulic Power Generation Maintenance Expenses	55,272	29	55,301			
39	546-550.1	Total Other Power Generation Operation Expenses	5,061,808	2,107,757	7,169,565			
40	551-554.1	Total Other Power Generation Maintenance Expenses	1,347,797	332	1,348,129			
41	555-557	Total Other Power Supply Operation Expenses	10,242,314	4,666,383	14,908,697			
42	560	Operation Supervision and Engineering	9,444,951	15,589,220	25,034,171			
43	561.1	Load Dispatch-Reliability	1,826		1,826			
44	561.2	Load Dispatch-Monitor and Operate Transmission System	2,302,447	5,315,409	7,617,856			
45	561.3	Load Dispatch-Transmission Service and Scheduling	3,528		3,528			
46	561.4	Scheduling, System Control and Dispatch Services						
47	561.5	Reliability Planning and Standards Development	308,547	181	308,728			
48	561.6	Transmission Service Studies	155,616		155,616			
49	561.7	Generation Interconnection Studies	116,618		116,618			
50	561.8	Reliability Planning and Standards Development Services	3,283		3,283			
51	562	Station Expenses (Major Only)	137,733		137,733			
52	563	Overhead Line Expenses (Major Only)	81,811		81,811			
53	564	Underground Line Expenses (Major Only)	242		242			
54	565	Transmission of Electricity by Others (Major Only)						
55	566	Miscellaneous Transmission Expenses (Major Only)	5,919,476	51,978	5,971,454			
56	567	Rents	6,179,683	7,762	6,187,445			
57	567.1	Operation Supplies and Expenses (Nonmajor Only)						
58		Total Transmission Operation Expenses	24,655,761	20,964,550	45,620,311			
59	568	Maintenance Supervision and Engineering (Major Only)	(27,130)		(27,130)			
60	569	Maintenance of Structures (Major Only)						
61	569.1	Maintenance of Computer Hardware						
62	569.2	Maintenance of Computer Software						
63	569.3	Maintenance of Communication Equipment						
64	569.4	Maintenance of Miscellaneous Regional Transmission Plant						
65	570	Maintenance of Station Equipment (Major Only)	65,504		65,504			
66	571	Maintenance of Overhead Lines (Major Only)	180,919		180,919			
67	572	Maintenance of Underground Lines (Major Only)	369		369			
68	573	Maintenance of Miscellaneous Transmission Plant (Major Only)						

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Line No.	Account Number (a)	Title of Account (b)	Associate Company Direct Cost (c)	Associate Company Indirect Cost (d)	Associate Company Total Cost (e)	Nonassociate Company Direct Cost (f)	Nonassociate Company Indirect Cost (g)	Nonassociate Company Total Cost (h)
69	574	Maintenance of Transmission Plant (Nonmajor Only)						
70		Total Transmission Maintenance Expenses	219,662		219,662			
71	575.1-575.8	Total Regional Market Operation Expenses	1,306,238		1,306,238			
72	576.1-576.5	Total Regional Market Maintenance Expenses						
73	580-589	Total Distribution Operation Expenses	32,768,333	6,493,127	39,261,460			
74	590-598	Total Distribution Maintenance Expenses	1,941,508		1,941,508			
75		Total Electric Operation and Maintenance Expenses	592,523,378	69,194,645	661,718,023			
76	700-798	Production Expenses (Provide selected accounts in a footnote)	341,268		341,268			
77	800-813	Total Other Gas Supply Operation Expenses	670,181		670,181			
78	814-826	Total Underground Storage Operation Expenses	37,361		37,361			
79	830-837	Total Underground Storage Maintenance Expenses	31,664		31,664			
80	840-842.3	Total Other Storage Operation Expenses	587,926		587,926			
81	843.1-843.9	Total Other Storage Maintenance Expenses	11,723		11,723			
82	844.1-846.2	Total Liquefied Natural Gas Terminaling and Processing Operation Expenses	24,932		24,932			
83	847.1-847.8	Total Liquefied Natural Gas Terminaling and Processing Maintenance Expenses	66,347		66,347			
84	850	Operation Supervision and Engineering	1,037,833	1,159,185	2,197,018			
85	851	System Control and Load Dispatching.	183,066	823,702	1,006,768			
86	852	Communication System Expenses	6		6			
87	853	Compressor Station Labor and Expenses	8,762		8,762			
88	854	Gas for Compressor Station Fuel						
89	855	Other Fuel and Power for Compressor Stations						
90	856	Mains Expenses	63,993		63,993			
91	857	Measuring and Regulating Station Expenses	6,013		6,013			
92	858	Transmission and Compression of Gas By Others						
93	859	Other Expenses	111,314	375	111,689			
94	860	Rents	1,051,177		1,051,177			
95		Total Gas Transmission Operation Expenses	2,462,164	1,983,262	4,445,426			
96	861	Maintenance Supervision and Engineering						
97	862	Maintenance of Structures and Improvements	9,828		9,828			
98	863	Maintenance of Mains	4,506		4,506			
99	864	Maintenance of Compressor Station Equipment	1,327		1,327			
100	865	Maintenance of Measuring And Regulating Station Equipment	1,908	21,634	23,542			
101	866	Maintenance of Communication Equipment	2		2			
102	867	Maintenance of Other Equipment						
103		Total Gas Transmission Maintenance Expenses	17,571	21,634	39,205			
104	870-881	Total Distribution Operation Expenses	13,265,295	10,864,787	24,130,082			

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Line No.	Account Number (a)	Title of Account (b)	Associate Company Direct Cost (c)	Associate Company Indirect Cost (d)	Associate Company Total Cost (e)	Nonassociate Company Direct Cost (f)	Nonassociate Company Indirect Cost (g)	Nonassociate Company Total Cost (h)
105	885-894	Total Distribution Maintenance Expenses	575,586		575,586			
106		Total Natural Gas Operation and Maintenance Expenses	18,092,018	12,869,683	30,961,701			
107	901	Supervision	1,228	273,100	274,328			
108	902	Meter reading expenses	293,296	6,200,322	6,493,618			
109	903	Customer records and collection expenses	12,507,717	47,138,632	59,646,349			
110	904	Uncollectible accounts						
111	905	Miscellaneous customer accounts expenses						
112	906	Total Customer Accounts Operation Expenses	12,802,241	53,612,054	66,414,295			
113	907	Supervision						
114	908	Customer assistance expenses	2,095,907	469,459	2,565,366			
115	909	Informational And Instructional Advertising Expenses	687,465	2,308,057	2,995,522			
116	910	Miscellaneous Customer Service And Informational Expenses	280,356		280,356			
117		Total Service and Informational Operation Accounts	3,063,728	2,777,516	5,841,244			
118	911	Supervision						
119	912	Demonstrating and Selling Expenses	7,845		7,845			
120	913	Advertising Expenses						
121	916	Miscellaneous Sales Expenses						
122		Total Sales Operation Expenses	7,845		7,845			
123	920	Administrative and General Salaries	28,308,410	149,382,165	177,690,575			
124	921	Office Supplies and Expenses	29,232,704	93,264,231	122,496,935			
125	923	Outside Services Employed	5,645,779	72,093,132	77,738,911			
126	924	Property Insurance	(297,232)	70,016	(227,216)			
127	925	Injuries and Damages	1,296,022	14,706,099	16,002,121			
128	926	Employee Pensions and Benefits	33,420,535	49,318,743	82,739,278			
129	928	Regulatory Commission Expenses	32,200	11,182	43,382			
130	930.1	General Advertising Expenses	1,458,484	7,941,268	9,399,752			
131	930.2	Miscellaneous General Expenses	1,082,411	7,772,292	8,854,703			
132	931	Rents	31,702,345	72,877,182	104,579,527			
133		Total Administrative and General Operation Expenses	131,881,658	467,436,310	599,317,968			
134	935	Maintenance of Structures and Equipment	30,700	1,541,028	1,571,728			
135		Total Administrative and General Maintenance Expenses	147,786,172	525,366,908	673,153,080			
136		Total Cost of Service	758,401,568	607,431,236	1,365,832,804			

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies (continued)

Line No.	Account Number (a)	Title of Account (b)	Total Charges for Services Direct Cost (i)	Total Charges for Services Indirect Cost (j)	Total Charges for Services Total Cost (k)
1	403-403.1	Depreciation Expense			
2	404-405	Amortization Expense			
3	407.3-407.4	Regulatory Debits/Credits – Net			
4	408.1-408.2	Taxes Other Than Income Taxes	8,079,395	12,490,524	20,569,919
5	409.1-409.3	Income Taxes	18,387,965		18,387,965
6	410.1-411.2	Provision for Deferred Taxes	(5,084,859)		(5,084,859)
7	411.1-411.2	Provision for Deferred Taxes – Credit			
8	411.6	Gain from Disposition of Service Company Plant			
9	411.7	Losses from Disposition of Service Company Plant			
10	411.4-411.5	Investment Tax Credit Adjustment			
11	411.10	Accretion Expense			
12	412	Costs and Expenses of Construction or Other Services	429,194,493		429,194,493
13	416	Costs and Expenses of Merchandising, Jobbing, and Contract Work for Associated Companies			
14	418	Non-operating Rental Income			
15	418.1	Equity in Earnings of Subsidiary Companies			
16	419	Interest and Dividend Income	1,376,644	351,324	1,727,968
17	419.1	Allowance for Other Funds Used During Construction			
18	421	Miscellaneous Income or Loss			
19	421.1	Gain on Disposition of Property			
20	421.2	Loss on Disposition Of Property			
21	425	Miscellaneous Amortization			
22	426.1	Donations	201,672	13,006,518	13,208,190
23	426.2	Life Insurance		(242,554)	(242,554)
24	426.3	Penalties	173,530	882	174,412
25	426.4	Expenditures for Certain Civic, Political and Related Activities	398,980	1,803,976	2,202,956
26	426.5	Other Deductions	197,208	563,878	761,086
27	427	Interest On Long-Term Debt			
28	428	Amortization of Debt Discount and Expense			
29	429	Amortization of Premium on Debt – Credit			
30	430	Interest on Debt to Associate Companies	4,882,814		4,882,814
31	431	Other Interest Expense		13,292	13,292
32	432	Allowance for Borrowed Funds Used During Construction			
33	500-509	Total Steam Power Generation Operation Expenses	31,086,485	7,313,059	38,399,544
34	510-515	Total Steam Power Generation Maintenance Expenses	10,224,130	904	10,225,034

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Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies (continued)

Line No.	Account Number (a)	Title of Account (b)	Total Charges for Services Direct Cost (i)	Total Charges for Services Indirect Cost (j)	Total Charges for Services Total Cost (k)
35	517-525	Total Nuclear Power Generation Operation Expenses	15,791,256		15,791,256
36	528-532	Total Nuclear Power Generation Maintenance Expenses	541,176		541,176
37	535-540.1	Total Hydraulic Power Generation Operation Expenses	2,227,084	363,312	2,590,396
38	541-545.1	Total Hydraulic Power Generation Maintenance Expenses	55,272	29	55,301
39	546-550.1	Total Other Power Generation Operation Expenses	5,061,808	2,107,757	7,169,565
40	551-554.1	Total Other Power Generation Maintenance Expenses	1,347,797	332	1,348,129
41	555-557	Total Other Power Supply Operation Expenses	10,242,314	4,666,383	14,908,697
42	560	Operation Supervision and Engineering	9,444,951	15,589,220	25,034,171
43	561.1	Load Dispatch-Reliability	1,826		1,826
44	561.2	Load Dispatch-Monitor and Operate Transmission System	2,302,447	5,315,409	7,617,856
45	561.3	Load Dispatch-Transmission Service and Scheduling	3,528		3,528
46	561.4	Scheduling, System Control and Dispatch Services			
47	561.5	Reliability Planning and Standards Development	308,547	181	308,728
48	561.6	Transmission Service Studies	155,616		155,616
49	561.7	Generation Interconnection Studies	116,618		116,618
50	561.8	Reliability Planning and Standards Development Services	3,283		3,283
51	562	Station Expenses (Major Only)	137,733		137,733
52	563	Overhead Line Expenses (Major Only)	81,811		81,811
53	564	Underground Line Expenses (Major Only)	242		242
54	565	Transmission of Electricity by Others (Major Only)			
55	566	Miscellaneous Transmission Expenses (Major Only)	5,919,476	51,978	5,971,454
56	567	Rents	6,179,683	7,762	6,187,445
57	567.1	Operation Supplies and Expenses (Nonmajor Only)			
58		Total Transmission Operation Expenses	24,655,761	20,964,550	45,620,311
59	568	Maintenance Supervision and Engineering (Major Only)	(27,130)		(27,130)
60	569	Maintenance of Structures (Major Only)			
61	569.1	Maintenance of Computer Hardware			
62	569.2	Maintenance of Computer Software			
63	569.3	Maintenance of Communication Equipment			
64	569.4	Maintenance of Miscellaneous Regional Transmission Plant			
65	570	Maintenance of Station Equipment (Major Only)	65,504		65,504
66	571	Maintenance of Overhead Lines (Major Only)	180,919		180,919
67	572	Maintenance of Underground Lines (Major Only)	369		369
68	573	Maintenance of Miscellaneous Transmission Plant (Major Only)			

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Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies (continued)

Line No.	Account Number (a)	Title of Account (b)	Total Charges for Services Direct Cost (i)	Total Charges for Services Indirect Cost (j)	Total Charges for Services Total Cost (k)
69	574	Maintenance of Transmission Plant (Nonmajor Only)			
70		Total Transmission Maintenance Expenses	219,662		219,662
71	575.1-575.8	Total Regional Market Operation Expenses	1,306,238		1,306,238
72	576.1-576.5	Total Regional Market Maintenance Expenses			
73	580-589	Total Distribution Operation Expenses	32,768,333	6,493,127	39,261,460
74	590-598	Total Distribution Maintenance Expenses	1,941,508		1,941,508
75		Total Electric Operation and Maintenance Expenses	592,523,378	69,194,645	661,718,023
76	700-798	Production Expenses (Provide selected accounts in a footnote)	341,268		341,268
77	800-813	Total Other Gas Supply Operation Expenses	670,181		670,181
78	814-826	Total Underground Storage Operation Expenses	37,361		37,361
79	830-837	Total Underground Storage Maintenance Expenses	31,664		31,664
80	840-842.3	Total Other Storage Operation Expenses	587,926		587,926
81	843.1-843.9	Total Other Storage Maintenance Expenses	11,723		11,723
82	844.1-846.2	Total Liquefied Natural Gas Terminaling and Processing Operation Expenses	24,932		24,932
83	847.1-847.8	Total Liquefied Natural Gas Terminaling and Processing Maintenance Expenses	66,347		66,347
84	850	Operation Supervision and Engineering	1,037,833	1,159,185	2,197,018
85	851	System Control and Load Dispatching.	183,066	823,702	1,006,768
86	852	Communication System Expenses	6		6
87	853	Compressor Station Labor and Expenses	8,762		8,762
88	854	Gas for Compressor Station Fuel			
89	855	Other Fuel and Power for Compressor Stations			
90	856	Mains Expenses	63,993		63,993
91	857	Measuring and Regulating Station Expenses	6,013		6,013
92	858	Transmission and Compression of Gas By Others			
93	859	Other Expenses	111,314	375	111,689
94	860	Rents	1,051,177		1,051,177
95		Total Gas Transmission Operation Expenses	2,462,164	1,983,262	4,445,426
96	861	Maintenance Supervision and Engineering			
97	862	Maintenance of Structures and Improvements	9,828		9,828
98	863	Maintenance of Mains	4,506		4,506
99	864	Maintenance of Compressor Station Equipment	1,327		1,327
100	865	Maintenance of Measuring And Regulating Station Equipment	1,908	21,634	23,542
101	866	Maintenance of Communication Equipment	2		2
102	867	Maintenance of Other Equipment			
103		Total Gas Transmission Maintenance Expenses	17,571	21,634	39,205
104	870-881	Total Distribution Operation Expenses	13,265,295	10,864,787	24,130,082

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies (continued)

Line No.	Account Number (a)	Title of Account (b)	Total Charges for Services Direct Cost (i)	Total Charges for Services Indirect Cost (j)	Total Charges for Services Total Cost (k)
105	885-894	Total Distribution Maintenance Expenses	575,586		575,586
106		Total Natural Gas Operation and Maintenance Expenses	18,092,018	12,869,683	30,961,701
107	901	Supervision	1,228	273,100	274,328
108	902	Meter reading expenses	293,296	6,200,322	6,493,618
109	903	Customer records and collection expenses	12,507,717	47,138,632	59,646,349
110	904	Uncollectible accounts			
111	905	Miscellaneous customer accounts expenses			
112	906	Total Customer Accounts Operation Expenses	12,802,241	53,612,054	66,414,295
113	907	Supervision			
114	908	Customer assistance expenses	2,095,907	469,459	2,565,366
115	909	Informational And Instructional Advertising Expenses	687,465	2,308,057	2,995,522
116	910	Miscellaneous Customer Service And Informational Expenses	280,356		280,356
117		Total Service and Informational Operation Accounts	3,063,728	2,777,516	5,841,244
118	911	Supervision			
119	912	Demonstrating and Selling Expenses	7,845		7,845
120	913	Advertising Expenses			
121	916	Miscellaneous Sales Expenses			
122		Total Sales Operation Expenses	7,845		7,845
123	920	Administrative and General Salaries	28,308,410	149,382,165	177,690,575
124	921	Office Supplies and Expenses	29,232,704	93,264,231	122,496,935
125	923	Outside Services Employed	5,645,779	72,093,132	77,738,911
126	924	Property Insurance	(297,232)	70,016	(227,216)
127	925	Injuries and Damages	1,296,022	14,706,099	16,002,121
128	926	Employee Pensions and Benefits	33,420,535	49,318,743	82,739,278
129	928	Regulatory Commission Expenses	32,200	11,182	43,382
130	930.1	General Advertising Expenses	1,458,484	7,941,268	9,399,752
131	930.2	Miscellaneous General Expenses	1,082,411	7,772,292	8,854,703
132	931	Rents	31,702,345	72,877,182	104,579,527
133		Total Administrative and General Operation Expenses	131,881,658	467,436,310	599,317,968
134	935	Maintenance of Structures and Equipment	30,700	1,541,028	1,571,728
135		Total Administrative and General Maintenance Expenses	147,786,172	525,366,908	673,153,080
136		Total Cost of Service	758,401,568	607,431,236	1,365,832,804

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule XVII - Analysis of Billing – Associate Companies (Account 457)

1. For services rendered to associate companies (Account 457), list all of the associate companies.

Line No.	Name of Associate Company (a)	Account 457.1 Direct Costs Charged (b)	Account 457.2 Indirect Costs Charged (c)	Account 457.3 Compensation For Use of Capital (d)	Total Amount Billed (e)
1	NSP-Minnesota	278,325,334	254,747,155	1,722,251	534,794,740
2	PSCo	304,861,946	211,922,938	1,816,191	518,601,075
3	SPS	116,822,005	77,185,254	1,071,156	195,078,415
4	NSP-Wisconsin	45,627,763	40,974,037	232,989	86,834,789
5	Xcel Energy, Inc.	3,687,140	21,913,331	31,265	25,631,736
6	Xcel Energy Joint Ventures	1,934,279			1,934,279
7	e-prime, Inc.	865,069			865,069
8	Nicollet Projects I, LLC	433,696	34,983	(42)	468,637
9	Xcel Energy Transmission Development Company, LLC	451,379	338	1,447	453,164
10	Capital Services, LLC	68,088	220,233	1,046	289,367
11	Xcel Energy WYCO, Inc.	71,737	200,980	7,200	279,917
12	Eloigne Company	79,660	159,741	635	240,036
13	Chippewa and Flambeau Improvement Company	56,957	4,282	309	61,548
14	Quixx Corporation	55,732			55,732
15	Xcel Energy Ventures Inc.	54,416		10	54,426
16	1480 Welton, Inc.	6,020	31,719	(2,308)	35,431
17	P.S.R. Investments, Inc.	8,830	9,160	533	18,523
18	WestGas Interstate, Inc.	15,638	1,892	13	17,543
19	Energy Impact Fund Investments	3,706	13,615	8	17,329
20	Clearwater Investments, Inc.	11,565	3,281	20	14,866
21	Xcel Energy Wholesale Group Inc.	14,445			14,445
22	Xcel Energy Transmission Holding Company, LLC	8,154	1,567	44	9,765
23	Xcel Energy Performance Contracting Inc.	8,098	839	18	8,955
24	Xcel Energy Retail Holdings Inc.	7,837		5	7,842
25	Xcel Energy Southwest Transmission Company, LLC	5,238	1,000	12	6,250
26	Xcel Energy Communications Group Inc.	4,842		2	4,844
27	Xcel Energy Markets Holdings, Inc.	4,736		3	4,739
28	Xcel Energy Ventures Holdings	4,379			4,379
29	Nicollet Holdings Company	4,334			4,334
30	Seren Innovations, Inc.	3,789			3,789
31	Xcel Energy International, Inc.	3,751			3,751
32	Xcel Energy West Transmission Company, LLC	3,717		(1)	3,716
33	Reddy Kilowatt Corporation	150	3,524	3	3,677
34	United Power and Land Company	1,239	1,166	2	2,407
35	NSP Lands, Inc.	2,023	201	1	2,225
36	Xcel Energy Investments	762		2	764
37	Quixxlin Corporation	300			300
38					
39					
40	**Total**	**753,518,754**	**607,431,236**	**4,882,814**	**1,365,832,804**

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
Xcel Energy Services Inc.	(1) X An Original (2) __ A Resubmission	/ /	2018

FOOTNOTE DATA

Schedule Page: 307 Line No.: 6 Column: e

Xcel Energy Joint Ventures:

This amount represents the combined total of all Xcel Energy Joint Ventures as listed below:

Joint Venture Sherco 3	$1,115,255
Joint Venture Hayden	380,935
Joint Venture CAPX	366,664
Joint Vent Comanche 3	71,425
	$1,934,279

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule XVIII – Analysis of Billing – Non-Associate Companies (Account 458)

1. For services rendered to nonassociate companies (Account 458), list all of the nonassociate companies. In a footnote, describe the services rendered to each respective nonassociate company.

Line No.	Name of Non-associate Company (a)	Account 458.1 Direct Costs Charged (b)	Account 458.2 Indirect Costs Charged (c)	Account 458.3 Compensation For Use of Capital (d)	Account 458.4 Excess or Deficiency on Servicing Non-associate Utility Companies (e)	Total Amount Billed (f)
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40	**Total**					

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule XIX - Miscellaneous General Expenses - Account 930.2

1. Provide a listing of the amount included in Account 930.2, "Miscellaneous General Expenses" classifying such expenses according to their nature. Amounts less than $50,000 may be grouped showing the number of items and the total for the group.
2. Payments and expenses permitted by Section 321 (b)(2) of the Federal Election Campaign Act, as amended by Public Law 94-283 in 1976 (2 U.S.C. 441(b)(2)) shall be separately classified.

Line No.	Title of Account (a)	Amount (b)
1	Utility Association Dues	4,358,674
2	Board of Directors Fess and Expenses	3,345,450
3	Shareholder Relation Expenses	1,030,123
4	SEC Filing and Shareholder Reporting Expenses	120,456
5		
6		
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40	**Total**	**8,854,703**

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
Xcel Energy Services Inc.	(1) X An Original (2) __ A Resubmission	/ /	2018

Schedule XX - Organization Chart

1. Provide a graphical presentation of the relationships and inter relationships within the service company that identifies lines of authority and responsibility in the organization.

Organization Chart	Service Function *
Chief Executive Officer (CEO)	Executive Management
Corporate Other	Accounting, Financial Reporting & Taxes
Corporate Secretary & Executive Services	Executive Management
Communications	Executive Management
Corporate Communications	Corporate Communications, Employee Communications
Strategic Communications	Corporate Communications, Employee Communications, Marketing & Sales
Corporate Compliance	Executive Management
Shareholder Relations	Corporate Communications, Investor Relations
Strategy & Planning	Corporate Strategy & Business Development
Utilities & Corporate Services	Executive Management
Employee & Business Services	Executive Management
Aviation & Travel Services	Aviation Services
Enterprise Security	Executive Management & Facilities & Real Estate
Property Services	Facilities Admin. Services & Facilities & Real Estate
Workforce Relations & Safety	Energy Supply Business Resources & Human Resources
Business Systems	Business Systems
Chief Administrative Office (CAO)	Executive Management, Government Affairs
Corporate Giving	Corporate Communications
Resource Planning	Energy Markets Regulated Trading & Marketing
Human Resources	Human Resources
Payroll	Payroll
Marketing	Marketing & Sales
Group President	Executive Management
NSPM President	Government Affairs & Rates & Regulation
NSPW President	Government Affairs & Rates & Regulation
PSCo President	Government Affairs & Rates & Regulation
SPS President	Government Affairs & Rates & Regulation
Financial Operations	Accounting, Financial Reporting & Taxes
Chief Financial Officer	Accounting, Financial Reporting & Taxes
Controller	Accounting, Financial Reporting & Taxes
Corporate Development	Corporate Strategy & Business Development
Financial Planning	Accounting, Financial Reporting & Taxes, Finance & Treasury, Rates & Regulation
Investor Relations	Investor Relations
Revenue Requirements	Rates & Regulation
Risk Management & Audit Services	Finance & Treasury, Internal Audit
Tax Services	Accounting, Financial Reporting & Taxes
Treasurer	Finance & Treasury

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
Xcel Energy Services Inc.	(1) X An Original (2) __ A Resubmission	/ /	2018

Schedule XX - Organization Chart

Corporate Policy & Federal Affairs	Government Affairs; Rates & Regulation & Business Systems
General Counsel	Legal
Claims	Claims Services
Legal Services	Legal
Operations Services	Executive Management
Commercial Operations	Energy Markets Regulated Trading & Marketing & Energy Markets – Fuel Procurement
Customer Care	Customer Service; Receipts Processing
Enterprise Transformation Office (ETO)	Information Technology
Distribution Operations	Construction O&M; Energy Delivery Marketing; Engineering/Design
Gas Systems	Engineering/Design; Construction O&M; Executive Management
Energy Supply	Energy Supply Business Resources
Engineering & Construction	Energy Supply Engineering & Environmental; Energy Supply Business Resources
Environmental	Energy Supply Engineering & Environmental
Operations (Regional Generation)	Energy Supply Business Resources
Technical Services	Energy Supply Business Resources
Supply Chain	Supply Chain; Supply Chain Special Programs; Payment & Reporting & Fleet
Transmission	Engineering/Design; Construction O&M; Engineering/Design-Electric Transmission/Substations

* The “Service Function” column sets forth the primary service functions for each area; however, others may be used based on a case-by-case basis depending on the specific work being performed.

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
Xcel Energy Services Inc.	(1) X An Original (2) __ A Resubmission	/ /	2018

Schedule XXI - Methods of Allocation

1. Indicate the service department or function and the basis for allocation used when employees render services to more than one department or functional group. If a ratio, include the numerator and denominator.
2. Include any other allocation methods used to allocate costs.

Service Department or Function	Basis of Allocation*
Executive Management Services	Executive Management indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.
Investor Relations	Investor Relations indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue ratio, the Employee Ratio and the Total Assets Ratio.
Internal Audit	Internal Audit indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.
Legal	Legal indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.
Claims Services	Claims Services costs will be direct charged. Any costs that cannot be direct charged will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.
Corporate Communications	Corporate Communications indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.
Employee Communications	Employee Communications indirect costs will be allocated based on the Employee Ratio.
Corporate Strategy & Business Development	Corporate Strategy & Business Development indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.
Government Affairs	Government Affairs indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.
Facilities & Real Estate	Facilities & Real Estate indirect costs will be allocated to the Operating Companies and Affiliate Companies based on the Employee Ratio.

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Facilities Administrative Services	Facilities Administrative Services indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.
Supply Chain	Supply Chain will be direct charged. Any management and oversight of the payment and reporting services activities that cannot be direct charged will be allocated using the Invoice Transaction Ratio.
Supply Chain Special Programs	Supply Chain Special Programs indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.
Human Resources	Human Resources indirect costs will be allocated based on the Employee Ratio.
Finance & Treasury	All Finance & Treasury indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio, except for: (1) indirect costs associated with proprietary trading activities, which will be allocated based on the Joint Operating Agreement Peak Hour Megawatt Load Ratio, provided, however, that indirect costs provided jointly for both generation trading activities and proprietary trading activities will be allocated based on the Joint Operating Agreement Labor Hours Ratio.
Accounting, Financial Reporting & Taxes	All Accounting, Financial Reporting & Taxes indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio, except for: (1) indirect costs incurred for services associated with proprietary trading activities, which will be allocated based on the Joint Operating Agreement Peak Hour Megawatt Load Ratio, provided, however, that indirect costs provided jointly for both generation trading activities and proprietary trading activities will be allocated based on the Joint Operating Agreement Labor Hours Ratio.
Payment & Reporting	Payment & Reporting indirect costs will be allocated to the Operating Companies based on the Invoice Transaction Ratio.
Receipts Processing	Receipts Processing indirect costs will be allocated based on the Customer Bills Ratio.
Payroll	Payroll indirect costs will be allocated based on the Employee Ratio.

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Rates & Regulation	Rates & Regulation indirect costs will be allocated to the Operating Companies based on the Direct Labor Ratio.
Energy Supply Engineering and Environmental	Energy Supply Engineering and Environmental services will be direct charged and administrative support functions that cannot be direct charged are allocated using a Total Plant Ratio.
Energy Supply Business Resources	Energy Supply Business Resources indirect costs will be allocated using the MWh Generation Ratio.
Energy Markets Regulated Trading & Marketing	Energy Markets Regulated Trading & Marketing indirect costs will be allocated to the Operating Companies based on the Total MWh Sales Ratio, except for: (1) indirect costs incurred for services associated with proprietary trading activities, which will be allocated based on the Joint Operating Agreement Peak Hour Megawatt Load Ratio, provided, however, that indirect costs provided jointly for both generation trading activities and proprietary trading activities will be allocated based on the Joint Operating Agreement Labor Hours Ratio.
Energy Markets - Fuel Procurement	Energy Markets Fuel Procurement indirect costs will be allocated based on the MWh Generation Ratio.
Energy Delivery Marketing	Energy Delivery Marketing will be direct charged.
Energy Delivery Construction, Operations & Maintenance (COM)	Energy Delivery COM indirect costs will be allocated based on the Delivery Services Gross Plant Ratio.
Energy Delivery Engineering/Design	Energy Delivery Engineering/Design services will be direct charged; administrative support functions that cannot be direct charged will be allocated using a Delivery Services Gross Plant Ratio based on the services being provided.
Marketing & Sales	Marketing & Sales indirect costs will be allocated based on the Revenue Ratio.
Customer Service	Customer Service indirect costs will be allocated based on the Customers Ratio. Indirect costs associated with administering low income and certified medical customer assistance programs will be allocated based on a composite of the Average of the Special Needs Customer Contacts Ratio and residential Customers Ratio.
Business Systems	Business Systems indirect costs will be allocated using any of the allocation ratios or combination of ratios.
Aviation Services	Aviation Services will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.

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Fleet	Fleet will be direct charged.

* Corporate Governance activities within this Service Function will be allocated using the average of the Revenue Ratio with intercompany dividends assigned to Xcel Energy Inc., Employee Ratio with number of common officers assigned to Xcel Energy Inc., and the Total Assets Ratio including Xcel Energy Inc.'s per book assets.

Allocation Ratios

The following ratios will be utilized as outlined above.

Revenue Ratio - Based on the sum of the monthly revenue amounts for the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Revenue Ratio with intercompany dividends assigned to Xcel Energy Inc.
- Based on the sum of the monthly revenue amounts for the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. Xcel Energy Inc. will be assigned the amount of intercompany dividends. This ratio will be determined annually, or at such time as may be required due to significant changes.

Employee Ratio - Based on the number of employees at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes

Employee Ratio with number of common officers assigned to Xcel Energy Inc. - Based on the number of employees at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. Xcel Energy Inc. will be assigned the number of common officers. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total Assets Ratio - Based on the total assets as of December 31 for the prior year, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total Assets Ratio including Xcel Energy Inc's Per Book Assets - Based on the total assets as of December 31 for the prior year, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. Xcel Energy Inc. will be assigned the per book assets of Xcel Energy Inc. This ratio will be determined annually, or at such time as may be required due to significant changes.

Square Footage Ratio - Based on the total square footage as of December 31 for the prior year, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Invoice Transaction Ratio - Based on the sum of the monthly number of invoice transactions processed for the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually or at such time as may be required due to significant changes.

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Customer Bills Ratio - Based on the average of the monthly total number of customer bills issued during the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

MWh Generation Ratio - Based on the sum of the monthly electric MWh generated by type of generator during the prior year ending December 31, the numerator of which is for an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total MWh Sales Ratio - Based on the sum of the monthly electric MWh hours sold during the prior year ending December 31, the numerator of which is for an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This includes sales to ultimate customers, wholesale customers, and non-requirement sales for resale. This ratio will be determined annually, or at such time as may be required due to significant changes.

Customers Ratio - Based on the average of the monthly total electric customers (and/or gas customers, or residential, business and large commercial and industrial customers where applicable) for the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Delivery Services Gross Plant Ratio - Based on transmission and distribution gross plant for the Delivery Business unit, both electric and gas or as may be applicable Electric Distribution for the prior year ending December 31, the numerator of which is an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Provided, however, as follows:
(1) If the costs being allocated are directly related only to electric transmission, the ratio shall be based on the electric transmission gross plant;
(2) If the costs being allocated are directly related only to electric distribution, the ratio shall be based on the electric distribution gross plant;
(3) If the costs being allocated are directly related only to gas transmission, the ratio shall be based on the gas transmission gross plant;
(4) If the costs being allocated are directly related only to gas distribution, the ratio shall be based on the gas distribution gross plant;
(5) If the costs being allocated are directly related only to electric transmission and electric distribution, the ratio shall be based on the sum of the electric transmission gross plant and the electric distribution gross plant;
(6) If the costs being allocated are directly related only to electric transmission and gas transmission, the ratio shall be based on the sum of the electric transmission gross plant and the gas transmission gross plant;
(7) If the costs being allocated are directly related only to electric transmission and gas distribution, the ratio shall be based on the sum of the electric transmission gross plant and the gas distribution gross plant;
(8) If the costs being allocated are directly related only to electric distribution and gas transmission, the ratio shall be based on the sum of the electric distribution gross plant and the gas transmission gross plant;
(9) If the costs being allocated are directly related only to electric distribution and gas distribution, the ratio shall be based on the sum of the electric distribution gross plant and the gas distribution gross plant;
(10) If the costs being allocated are directly related only to gas transmission and gas distribution, the ratio shall be based on the sum of the gas transmission gross plant and the gas distribution gross plant;
(11) If the costs being allocated are directly related only to electric transmission, electric distribution, and gas transmission, the ratio shall be based on the sum of the electric transmission gross plant, the electric distribution gross plant, and the gas transmission gross plant;
(12) If the costs being allocated are directly related only to electric transmission, electric distribution, and gas distribution, the ratio shall be based on the sum of the electric transmission gross plant, the electric distribution gross plant, and the gas distribution gross plant;

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(13) If the costs being allocated are directly related only to electric transmission, gas transmission, and gas distribution, the ratio shall be based on the sum of the electric transmission gross plant, the gas transmission gross plant, and the gas distribution gross plant;
(14) If the costs being allocated are directly related only to electric distribution, gas transmission, and gas distribution, the ratio shall be based on the sum of the electric distribution plant, the gas transmission gross plant, and the gas distribution gross plant.

Meters Ratio - Based on the number of meters at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Customer Contacts Ratio - Based on the total annual number of customer contacts at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

If the costs being allocated are directly related only to the support of special needs customers, such as those receiving low income energy assistance program and those having certified medical conditions, the Special Needs Customer Contacts Ratio shall be used.

Special Needs Customer Contacts Ratio - Based on the number of contacts received by the special needs customer department at the end of the prior year ending December 31. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. The ratio will be determined annually, or at such a time as may be required due to significant changes.

Accounts Payable Transactions Ratio - Based on the total annual number of accounts payable transactions by system application at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Inventory Transactions Ratio - Based on the total annual number of inventory transactions by system application at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Work Management Transactions Ratio - Based on the total annual number of work management transactions by system application at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Purchasing Transactions Ratio - Based on the total annual number of purchasing transactions by system application at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Total Plant Ratio - Based on total property, plant and equipment at the end of the prior year ending December 31, the numerator of which is an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Provided, however, as follows:
(1) If the costs being allocated are directly related only to electric production, the ratio shall be based on the total electric production plant;

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(2) If the costs being allocated are directly related only to electric transmission, the ratio shall be based on the total electric transmission plant;
(3) If the costs being allocated are directly related only to electric distribution, the ratio shall be based on the total electric distribution plant;
(4) If the costs being allocated are directly related only to gas transmission, the ratio shall be based on the total gas transmission plant;
(5) If the costs being allocated are directly related only to gas distribution, the ratio shall be based on the total gas distribution plant;
(6) If the costs being allocated are directly related only to intangible plant, the ratio shall be based on the total intangible plant;
(7) If the costs being allocated are directly related only to electric production and electric transmission, the ratio shall be based on the sum of the total electric production plant and the total electric transmission plant;
(8) If the costs being allocated are directly related only to electric production and electric distribution, the ratio shall be based on the sum of the total electric production plant and the total electric distribution plant;
(9) If the costs being allocated are directly related only to electric production and gas transmission, the ratio shall be based on the sum of the total electric production plant and the total gas transmission plant;
(10) If the costs being allocated are directly related only to electric production and gas distribution, the ratio shall be based on the sum of the total electric production plant and the total gas distribution plant;
(11) If the costs being allocated are directly related only to electric production and intangible plant, the ratio shall be based on the sum of the total electric production plant and the total intangible plant;
(12) If the costs being allocated are directly related only to electric transmission and electric distribution, the ratio shall be based on the sum of the total electric transmission plant and the total electric distribution plant;
(13) If the costs being allocated are directly related only to electric transmission and gas transmission, the ratio shall be based on the sum of the total electric transmission plant and the total gas transmission plant;
(14) If the costs being allocated are directly related only to electric transmission and gas distribution, the ratio shall be based on the sum of the total electric transmission plant and the total gas distribution plant;
(15) If the costs being allocated are directly related only to electric transmission and intangible plant, the ratio shall be based on the sum of the total electric transmission plant and the total intangible plant;
(16) If the costs being allocated are directly related only to electric distribution and gas transmission, the ratio shall be based on the sum of the total electric distribution plant and the total gas transmission plant;
(17) If the costs being allocated are directly related only to electric distribution and gas distribution, the ratio shall be based on the sum of the total electric distribution plant and the total gas distribution plant;
(18) If the costs being allocated are directly related only to electric distribution and intangible plant, the ratio shall be based on the sum of the total electric distribution plant and the total intangible plant;
(19) If the costs being allocated are directly related only to gas transmission and gas distribution, the ratio shall be based on the sum of the total gas transmission plant and the total gas distribution plant;
(20) If the costs being allocated are directly related only to gas transmission and intangible plant, the ratio shall be based on the sum of the total gas transmission plant and the total intangible plant;
(21) If the costs being allocated are directly related only to gas distribution and intangible plant, the ratio shall be based on the sum of the total gas distribution plant and the total intangible plant;
(22) If the costs being allocated are directly related only to electric production, electric transmission, and electric distribution, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, and the total electric distribution plant;
(23) If the costs being allocated are directly related only to electric production, electric transmission, and gas transmission, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, and the total gas transmission plant;
(24) If the costs being allocated are directly related only to electric production, electric transmission, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, and the total gas distribution plant;
(25) If the costs being allocated are directly related only to electric production, electric transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, and the total intangible plant;

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(26) If the costs being allocated are directly related only to electric production, electric distribution, and gas transmission, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, and the total gas transmission plant;
(27) If the costs being allocated are directly related only to electric production, electric distribution, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, and the total gas distribution plant;
(28) If the costs being allocated are directly related only to electric production, electric distribution, and intangible, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, and the total intangible plant;
(29) If the costs being allocated are directly related only to electric production, gas transmission, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total gas transmission plant, and the total gas distribution plant;
(30) If the costs being allocated are directly related only to electric production, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total gas transmission plant, and the total intangible plant;
(31) If the costs being allocated are directly related only to electric production, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total gas distribution plant, and the total intangible plant;
(32) If the costs being allocated are directly related only to electric transmission, electric distribution, and gas transmission, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, and the total gas transmission plant;
(33) If the costs being allocated are directly related only to electric transmission, electric distribution, and gas distribution, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, and the total gas distribution plant;
(34) If the costs being allocated are directly related only to electric transmission, electric distribution, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, and the total intangible plant;
(35) If the costs being allocated are directly related only to electric transmission, gas transmission, and gas distribution, the ratio shall be based on the sum of the total electric transmission plant, the total gas transmission plant, and the total gas distribution plant;
(36) If the costs being allocated are directly related only to electric transmission, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total gas transmission plant, and the total intangible plant;
(37) If the costs being allocated are directly related only to electric transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total gas distribution plant, and the total intangible plant;
(38) If the costs being allocated are directly related only to electric distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric distribution plant, the total gas transmission plant, and the total intangible plant;
(39) If the costs being allocated are directly related only to electric distribution, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric distribution plant, the total gas distribution plant, and the total intangible plant;
(40) If the costs being allocated are directly related only to electric distribution, gas distribution, and gas transmission, the ratio shall be based on the sum of the total electric distribution plant, the total gas distribution plant, and the total gas transmission plant;
(41) If the costs being allocated are directly related only to gas transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total gas transmission plant, the total gas distribution plant, and the total intangible plant;
(42) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, and gas transmission, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, and the total gas transmission plant;
(43) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, and the total gas distribution plant;
(44) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, and the total intangible plant;

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(45) If the costs being allocated are directly related only to electric production, electric transmission, gas transmission, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total gas transmission plant, and the total gas distribution plant;
(46) If the costs being allocated are directly related only to electric production, electric transmission, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total gas transmission plant, and the total intangible plant;
(47) If the costs being allocated are directly related only to electric production, electric distribution, gas transmission, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, the total gas transmission plant, and the total gas distribution plant;
(48) If the costs being allocated are directly related only to electric production, electric distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, the total gas transmission plant, and the total intangible plant;
(49) If the costs being allocated are directly related only to electric production, electric distribution, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, the total gas distribution plant, and the total intangible plant;
(50) If the costs being allocated are directly related only to electric production, gas transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total gas transmission plant, the total gas distribution plant, and the total intangible plant;
(51) If the costs being allocated are directly related only to electric transmission, electric distribution, gas transmission, and gas distribution, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, the total gas transmission plant, and the total gas distribution plant;
(52) If the costs being allocated are directly related only to electric transmission, electric distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, the total gas transmission plant, and the total intangible plant;
(53) If the costs being allocated are directly related only to electric transmission, electric distribution, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, the total gas distribution plant, and the total intangible plant;
(54) If the costs being allocated are directly related only to electric transmission, gas transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total gas transmission plant, the total gas distribution plant, and the total intangible plant;
(55) If the costs being allocated are directly related only to electric distribution, gas transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric distribution plant, the total gas transmission plant, the total gas distribution plant, and the total intangible plant;
(56) If the costs being allocated are directly related only to electric production, electric transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total gas distribution plant, and the total intangible plant;
(57) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, gas distribution, and gas transmission, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, the total gas distribution plant, and the total gas transmission plant;
(58) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, the total gas transmission plant, and the total intangible plant;
(59) If the costs being allocated are directly related only to electric production, electric distribution, gas distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, the total gas distribution plant, the total gas transmission plant, and the total intangible plant;
(60) If the costs being allocated are directly related only to electric production, electric transmission, gas distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total gas distribution plant, the total gas transmission plant, and the total intangible plant;
(61) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, the total gas distribution plant, and the total intangible plant;
(62) If the costs being allocated are directly related only to electric transmission, electric distribution, gas distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, the total gas distribution plant, the total gas transmission plant, and the total intangible plant.

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Total Phones Ratio - Based on the number of phones at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Total Radios Ratio - Based on the number of radios at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Total Computers Ratio - Based on the number of computers at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Total Software Applications Users Ratio - Based on the number of users of a specific software application at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Joint Operating Agreement Peak Hour Megawatt Load Ratio - Based on that certain Joint Operating Agreement among Northern States Power Company, a Minnesota corporation, Northern States Power Company, a Wisconsin corporation, Public Service Company of Colorado, Southwestern Public Service Company, and Xcel Energy Services Inc., as agent, dated as of October 1, 2004, as may be amended from time to time, that designates costs to be allocated based on peak hour of megawatt load for previous year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Joint Operating Agreement Labor Hours Ratio - Based on that certain Joint Operating Agreement among Northern States Power Company, a Minnesota corporation, Northern States Power Company, a Wisconsin corporation, Public Service Company of Colorado, Southwestern Public Service Company, and Xcel Energy Services Inc., as agent, dated as of October 1, 2004, as may be amended from time to time, that designates costs to be allocated based on labor hours at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Direct Labor Ratio – Based on fully-loaded direct-charged Rates and Regulation labor dollars to individual operating affiliates by the Rates and Regulation service function. The numerator of which is the fully-loaded direct-charges labor dollars to individual operating affiliates by Rates and Regulation service function and the denominator of which is the total fully-loaded direct charged labor dollars to all affiliates by the Rates and Regulation service function.

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Utility Allocation Factors
2020 Test Year Budget

Cost Categories	Allocation Method	Reasonableness of Allocation Method	2020 Test Year Percentages	
			Electric	Gas
FERC Accounts 901-917 (excluding commodity bad debt in FERC 904)	Customer bill counts for the electric and gas departments.	Using Customer bill counts is reasonable because costs recorded in FERC accounts 901-917 are customer related.	79.7150%	20.2850%
FERC 904 (commodity bad debt portion)	Average total electric and gas revenues for the previous four years	Using a revenue allocator is reasonable because commodity bad debt costs have a cost-causative relationship with uncollectible utility revenues.	76.9704%	11.1725%
FERC Accounts 920-924	3-factor allocation for the electric and gas departments.	Using a 3-factor allocation is reasonable because costs recorded in FERC accounts 920-924 are general in nature.	91.5376%	8.4624%
FERC Accounts 925-926	Operating labor for the electric and gas departments.	Using Operating labor is reasonable because costs recorded in FERC accounts 925-926 are employee related.	92.0598%	7.9402%
FERC Accounts 927-935	3-factor for the electric and gas departments.	Using a 3-factor allocation is reasonable because costs recorded in FERC accounts 927-937 are general in nature.	91.5376%	8.4624%

Administrative Services Agreements Charges
between Regulated Utility Operating Companies and NSPM
2020 Budget

	Budget Year 2020	Total by Operating Co	Total for SPS and PSCo
NSPM charges to NSPW			
Facilities Overheads	$ 14,914		
Labor Additives	$ 1,414		
Total Charges to NSPW		$ 16,328	
NSPW charges to NSPM			
Facilities Overheads	$ 28,428		
Labor Additives	$ 1,260		
Total Charges to NSPM		$ 29,688	
Charges from/to NSPW		$ 46,016	
NSPM charges to PSCo			
Facilities Overheads	$ 3,538		
Labor Additives	$ 334		
Total Charges to PSCo		$ 3,872	
PSCo charges to NSPM			
Facilities Overheads	$ 3,833		
Labor Additives	$ 51		
		$ 3,884	$ 7,756
NSPM charges to SPS			
Facilities Overheads	$ 2,233		
Labor Additives	$ 210		
Total Charges to SPS		$ 2,443	
SPS Charges to NSPM			
Facilities Overheads	$ 643		
Labor Additives	$ 9		
		$ 652	$ 3,095
Charges from/to Regulated Utility Operating Companies other than NSPW			$ 10,851

Definitions:
NSPM - Northern States Power Company-Minnesota
NSPW - Northern States Power Company-Wisconsin
PSCo - Public Service Company of Colorado
SPS - Southwestern Public Service

Non-Regulated Business Activity Significance
Fiscal Year Ended 12/31/2018

	Consolidated Total NSPM		All Other Non-regulated		% of Total
Operating revenues	$ 5,121,900	(1)(2)	$ 30,800	(1)(2)	0.60%
Less: Interest charges and financing costs	(214,300)	(1)	-	(1)	
Income tax expense	(27,200)	(1)	(600)	(1)	
Net income	(492,300)	(1)	(7,700)	(1)	
Subtotal	$ 4,388,100	(3)	$ 22,500	(3)	
Add: Other expense, net	(6,500)	(2)	-		
Allowance for funds used during construction - equity	23,800	(2)	-		
Operating expenses	$ 4,405,400	(2)	$ 22,500	(3)	
Less: Purchased cost of goods sold (COGS)	(2,065,900)	(3)	(19,700)	(2)	
Operating expense, net of purchased COGS	$ 2,339,500	(3)	$ 2,800	(3)	0.12%

<u>Calculation of Purchased Fuel, Power & Gas Expense (Purchased COGS)</u>

Electric fuel and purchased power	$ 1,701,100	(2)		
Cost of natural gas sold and transported	345,100	(2)		
Cost of sales - other	19,700	(2)	$ 19,700	(2)
Purchased COGS	$ 2,065,900	(3)	$ 19,700	

<u>Calculation of Operating Expenses excluding Purchased COGS</u>

Operating and maintenance expense	$ 1,223,300	(2)
Conservation program expenses	118,000	(2)
Depreciation and amortization	741,600	(2)
Taxes (other than income taxes)	256,600	(2)
Operating expense, net of purchased COGS	$ 2,339,500	(3)
Total Operating Expenses (excluding interest and income tax expenses)	$ 4,405,400	(2)

(1) From page 49 of Northern States Power Company's (NSPM) Form 10-K filed with the SEC for the fiscal year ended December 31, 2018. According to NSPM, the "All Other" column primarily includes appliance repair services, non-utility real estate activities, and revenues associated with processing solid waste into refuse-derived fuel.

(2) From page 23 of Northern States Power Company's (NSPM) Form 10-K filed with the SEC for the fiscal year ended December 31, 2018.

(3) Calculated number from above.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2018
or

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

001-31387	41-1967505
(Commission File Number)	(I.R.S. Employer Identification No.)

(Registrant, State of Incorporation or Organization, Address of Principal Executive Officers and Telephone Number)

Northern States Power Company

(a Minnesota corporation)
414 Nicollet Mall
Minneapolis, MN 55401
612-330-5500

Securities registered pursuant to Section 12(b) of the Act: None

Securities registered pursuant to section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. ☒ Yes ☐ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. ☐ Yes ☒ No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☒ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 and Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). ☒ Yes ☐ No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulations S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer", "accelerated filer", "smaller reporting company", and "emerging growth company" in Rule 12b-2 of the Exchange Act. ☐ Large accelerated filer ☐ Accelerated filer ☒ Non-accelerated filer ☐ Smaller Reporting Company ☐ Emerging growth company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). ☐ Yes ☒ No

As of Feb. 22, 2019, 1,000,000 shares of common stock, par value $0.01 per share, were outstanding, all of which were held by Xcel Energy Inc., a Minnesota corporation.

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Item 14 of Form 10-K is set forth under the heading "Independent Registered Public Accounting Firm – Audit and Non-Audit Fees" in Xcel Energy Inc.'s definitive Proxy Statement for the 2019 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about April 1, 2019. Such information set forth under such heading is incorporated herein by this reference hereto.

Northern States Power Company meets the conditions set forth in General Instructions I(1)(a) and (b) of Form 10-K and is therefore filing this form with the reduced disclosure format permitted by General Instruction I(2).

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This Form 10-K is filed by NSP-Minnesota. NSP-Minnesota is a wholly owned subsidiary of Xcel Energy Inc. Additional information on Xcel Energy is available in various filings with the SEC. This report should be read in its entirety.

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PART I

Item l — Business

ABBREVIATIONS AND INDUSTRY TERMS

Xcel Energy Inc.'s Subsidiaries and Affiliates (current and former)	
NSPM	NSP-Minnesota
NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP System	The electric production and transmission system of NSP-Minnesota and NSP-Wisconsin operated on an integrated basis and managed by NSP-Minnesota
NSP-Wisconsin	Northern States Power Company, a Wisconsin corporation
PSCo	Public Service Company of Colorado
SPS	Southwestern Public Service Company
Utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
Xcel Energy	Xcel Energy Inc. and its subsidiaries

Federal and State Regulatory Agencies	
D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
DOC	Minnesota Department of Commerce
DOE	United States Department of Energy
DOT	United States Department of Transportation
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
MPUC	Minnesota Public Utilities Commission
NDPSC	North Dakota Public Service Commission
NERC	North American Electric Reliability Corporation
NRC	Nuclear Regulatory Commission
OAG	Minnesota Office of the Attorney General
PHMSA	Pipeline and Hazardous Materials Safety Administration
SDPUC	South Dakota Public Utilities Commission
SEC	Securities and Exchange Commission

Electric, Purchased Gas and Resource Adjustment Clauses	
CIP	Conservation improvement program
EIR	Environmental improvement rider
FCA	Fuel clause adjustment
GUIC	Gas utility infrastructure cost rider
PGA	Purchased gas adjustment
RDF	Renewable development fund
RER	Renewable energy rider
RES	Renewable energy standard
SEP	State energy policy rider
TCR	Transmission cost recovery adjustment

Other	
AFUDC	Allowance for funds used during construction
ALJ	Administrative law judge
ARAM	Average rate assumption method
ARO	Asset retirement obligation
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
C&I	Commercial and Industrial
CAPM	Capital Asset Pricing Model
CapX2020	Alliance of electric cooperatives, municipals and investor-owned utilities in the upper Midwest involved in a joint transmission line planning and construction effort
CCR	Coal combustion residuals
CO_2	Carbon dioxide
Corps	U.S. Army Corps of Engineers
CPP	Clean Power Plan
CWA	Clean Water Act
CWIP	Construction work in progress
DCF	Discounted Cash Flows
ELG	Effluent limitations guidelines
EMANI	European Mutual Association for Nuclear Insurance
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
FTR	Financial transmission right
GAAP	Generally accepted accounting principles
GE	General Electric
GHG	Greenhouse gas
IPP	Independent power producing entity
IRP	Integrated Resource Plan
ISFSI	Independent spent fuel storage installation
ITC	Investment tax credit
LLW	Low-level radioactive waste
LNG	Liquefied natural gas
MGP	Manufactured gas plant
MISO	Midcontinent Independent System Operator, Inc.
Moody's	Moody's Investor Services
Native load	Customer demand of retail and wholesale customers that a utility has an obligation to serve under statute or long-term contract.
NAV	Net asset value
NEIL	Nuclear Electric Insurance Ltd.
NETO	New England Transmission Owners
NOL	Net operating loss
O&M	Operating and maintenance
Paris Agreement	Establishes a framework for GHG mitigation actions by all countries ("nationally determined contributions")
PI	Prairie Island nuclear generating plant
Pipeline Safety Act	Pipeline Safety, Regulatory Certainty, and Job Creation Act
PPA	Purchased power agreement
PTC	Production tax credit
REC	Renewable energy credit
ROE	Return on equity
RTO	Regional Transmission Organization
SAB	Staff Accounting Bulletin
SAB 118	Income Tax Accounting Implications of the Tax Cuts and Jobs Act
SERP	Supplemental executive retirement plan
SMMPA	Southern Minnesota Municipal Power Agency
Standard & Poor's	Standard & Poor's Ratings Services
TCJA	2017 federal tax reform enacted as Public Law No: 115-97, commonly referred to as the Tax Cuts and Jobs Act
TO	Transmission owner
VaR	Value at Risk
VIE	Variable interest entity
Westinghouse	Westinghouse Electric Corporation

Measurements	
Bcf	Billion cubic feet
KV	Kilovolts
KWh	Kilowatt hours
MMBtu	Million British thermal units
MW	Megawatts
MWh	Megawatt hours

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Forward-Looking Statements

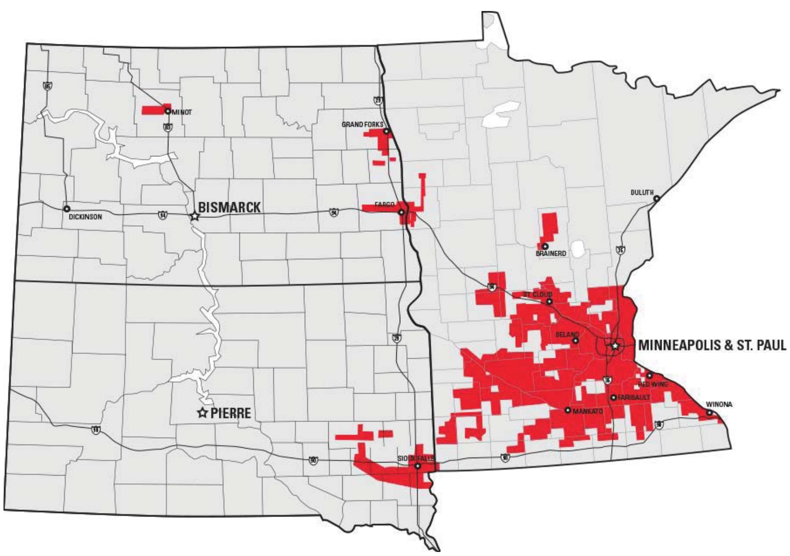
Except for the historical statements contained in this report, the matters discussed herein are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, assumptions and other statements are intended to be identified in this document by the words "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should," "will," "would" and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we expressly disclaim any obligation to update any forward-looking information. The following factors, in addition to those discussed elsewhere in this Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2018 (including risk factors listed from time to time by NSP-Minnesota in reports filed with the SEC, including "Risk Factors" in Item 1A of this Annual Report on Form 10-K hereto), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: changes in environmental laws and regulations; climate change and other weather, natural disaster and resource depletion, including compliance with any accompanying legislative and regulatory changes; ability to recover costs from customers; reductions in our credit ratings and the cost of maintaining certain contractual relationships; general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of NSP-Minnesota and its subsidiaries to obtain financing on favorable terms; availability or cost of capital; our customers' and counterparties' ability to pay their debts to us; assumptions and costs relating to funding our employee benefit plans and health care benefits; tax laws; operational safety, including our nuclear generation facilities; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices; costs of potential regulatory penalties; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; fuel costs; and employee work force and third party contractor factors.

Where To Find More Information

NSP-Minnesota is a wholly owned subsidiary of Xcel Energy Inc., and Xcel Energy's website address is www.xcelenergy.com. Xcel Energy makes available, free of charge through its website, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after the reports are electronically filed with or furnished to the SEC. The SEC maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically at http://www.sec.gov.

COMPANY OVERVIEW

NSP-Minnesota was incorporated in 2000 under the laws of Minnesota. NSP-Minnesota conducts business in Minnesota, North Dakota and South Dakota and has electric operations in all three states including the generation, purchase, transmission, distribution and sale of electricity as managed on the NSP System. NSP-Minnesota also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas in Minnesota and North Dakota.



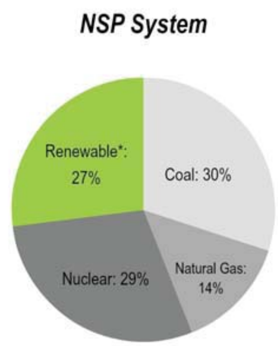
NSP-Minnesota	
Electric customers	1.5 million
Natural gas customers	0.5 million
Consolidated earnings contribution	35% to 45%
Total assets	$18.5 billion
Electric generating capacity	7,530 MW
Gas storage capacity	14.7 Bcf

ELECTRIC UTILITY OPERATIONS

Electric Operating Statistics

	Year Ended Dec. 31		
	2018	2017	2016
Electric sales (Millions of KWh)			
Residential	10,476	9,900	10,107
Large C&I	8,877	8,829	8,890
Small C&I	15,323	15,104	15,377
Public authorities and other	224	225	248
Total retail	34,900	34,058	34,622
Sales for resale	6,736	5,739	5,333
Total energy sold	41,636	39,797	39,955
Number of customers at end of period			
Residential	1,318,095	1,306,825	1,296,852
Large C&I	558	557	555
Small C&I	157,636	156,386	155,865
Public authorities and other	8,124	7,774	7,368
Total retail	1,484,413	1,471,542	1,460,640
Wholesale	11	8	10
Total customers	1,484,424	1,471,550	1,460,650
Electric revenues (Millions of Dollars)			
Residential	$ 1,364.9	$ 1,320.5	$ 1,310.3
Large C&I	682.2	690.2	686.2
Small C&I	1,500.6	1,560.3	1,513.0
Public authorities and other	35.4	35.5	35.4
Total retail	3,583.1	3,606.5	3,544.9
Wholesale	193.4	161.6	124.9
Interchange revenues from NSP-Wisconsin	473.7	490.2	475.5
Other electric revenues	257.8	283.4	259.3
Total electric revenues	$ 4,508.0	$ 4,541.7	$ 4,404.6
KWh sales per retail customer	23,511	23,144	23,703
Revenue per retail customer	$ 2,414	$ 2,451	$ 2,427
Residential revenue per KWh	13.03¢	13.34¢	12.96¢
Large C&I revenue per KWh	7.69	7.82	7.72
Small C&I revenue per KWh	9.79	10.33	9.84
Total retail revenue per KWh	10.27	10.59	10.24
Wholesale revenue per KWh	2.87	2.82	2.34

Energy Sources 2018



*Distributed generation from the Solar*Rewards® program is not included (approximately 32 million KWh for 2018).

Energy Source Statistics

In 2018, of the NSP System's total energy generation, 77% was owned and 23% was purchased. In 2017, 75% was owned and 25% was purchased.

Renewable Sources

NSP-Minnesota's renewable energy portfolio includes wind, hydroelectric, biomass and solar power from both owned generating facilities and PPAs. As of Dec. 31, 2018, NSP-Minnesota was in compliance with its applicable renewable portfolio standards. Renewable percentages will vary year over year based on local weather, system demand and transmission constraints.

NSP System

Renewable energy as a percentage of the NSP System's total:

	2018	2017
Wind	16.4%	18.3%
Hydroelectric	5.8	6.3
Biomass and solar	4.8	4.2
Renewable	27.0%	28.8%

Wind — The NSP System has more than 130 PPAs ranging from under one MW to more than 200 MW. The NSP System owns and operates five wind farms with 840 MW, net, of capacity.

- The NSP System had approximately 2,550 MW and 2,600 MW of wind energy on its system at the end of 2018 and 2017, respectively.
- Average cost per MWh of wind energy under existing PPAs was approximately $44 for 2018 and 2017.
- Average cost per MWh of wind energy from owned generation was approximately $37 and $42 for 2018 and 2017, respectively.

Non-Renewable Sources

Delivered cost per MMBtu of each significant category of fuel consumed for owned electric generation and the percentage of total fuel requirements represented by each category of fuel:

	Coal (a)		Nuclear		Natural Gas	
	Cost	Percent	Cost	Percent	Cost	Percent
2018	$ 2.13	42%	$ 0.80	45%	$ 3.87	13%
2017	2.08	45	0.78	45	4.10	10

(a) Includes refuse-derived fuel and wood.

Weighted average cost per MMBtu of all fuels for owned electric generation was $1.78 in 2018 and $1.72 in 2017.

See Items 1A and 7 for further information.

Coal — Inventory maintained (in days):

Normal	Dec. 31, 2018 Actual	Dec. 31, 2017 Actual (a)
35 - 50	47	53

(a) Milder weather, purchase commitments and low power and natural gas prices impacted coal inventory levels.

Coal requirements (in million tons) was 7.8 in 2018 and 8.0 in 2017. Coal supply as a percentage of requirements for 2019 is 8.4 million tons or 76% of contracted coal supply. The general coal purchasing objective is to contract for approximately 75% of year one requirements, 40% of year two requirements and 20% of year three requirements. Increase in estimated million tons was due to lower delivered coal prices at Sherco in January 2019, combined with higher future forecasted gas prices for 2019 (higher burn forecast).

Contracted coal transportation as a percentage of requirements in 2019 and 2020 is 100%.

Natural Gas — Natural gas supplies, transportation and storage services for power plants are procured to provide an adequate supply of fuel. Remaining requirements are procured through a liquid spot market. Generally, natural gas supply contracts have variable pricing that is tied to natural gas indices. Natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified volumes or payments in lieu of delivery.

Contracts and commitments at Dec. 31:

(Millions of Dollars)	Gas Supply	Gas Transportation and Storage (a)
2018	$ —	$ 406
2017	—	398
Year of Expiration	N/A	2020 - 2037

(a) For incremental supplies, there are limited on-site fuel storage facilities, with a primary reliance on the spot market.

Nuclear — NSP-Minnesota secures contracts for uranium concentrates, uranium conversion, uranium enrichment and fuel fabrication to operate its nuclear plants. The contract strategy involves a portfolio of spot purchases and medium and long-term contracts for uranium concentrates, conversion services and enrichment services with multiple producers and with a focus on diversification to minimize potential impacts caused by supply interruptions due to geographical and world political issues.

- Current nuclear fuel supply contracts cover 100% of uranium concentrates requirements through 2021 and approximately 51% of the requirements for 2022 - 2033;

- Current contracts for conversion services cover 100% of the requirements through 2021 and approximately 43% of the requirements for 2022 - 2033; and
- Current enrichment service contracts cover 100% of the requirements through 2025 and approximately 19% of the requirements for 2026 - 2033.

Fabrication services for Monticello and PI are 100% committed through 2030 and 2027, respectively.

NSP-Minnesota expects sufficient uranium concentrates, conversion services and enrichment services to be available for the requirements of its nuclear generating plants. Some exposure to market price volatility will remain due to index-based pricing structures contained in supply contracts.

See Item 7 for further information.

Capacity and Demand

Uninterrupted system peak demand for the NSP System's electric utility for the last two years, is as follows:

System Peak Demand (in MW)

2018		2017	
8,927	June 29	8,546	July 17

The peak demand typically occurs in the summer. The increase in peak load from 2017 to 2018 is partly due to warmer weather in 2018.

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — Retail rates, services and other aspects of NSP-Minnesota's operations are regulated by the MPUC, the NDPSC and the SDPUC. The MPUC also has regulatory authority over security issuances, certain property transfers, mergers, dispositions of assets and transactions between NSP-Minnesota and its affiliates. In addition, the MPUC reviews and approves NSP-Minnesota's IRPs for meeting future energy needs. In addition, MPUC certifies the need and siting for generating plants greater than 50 MW and transmission lines greater than 100 KV that will be located within the state. The NDPSC and SDPUC have regulatory authority over generation and transmission facilities, along with the siting and routing of new generation and transmission facilities in North Dakota and South Dakota, respectively.

NSP-Minnesota is subject to the jurisdiction of the FERC for its wholesale electric operations, hydroelectric licensing, accounting practices, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transfers and mergers, and natural gas transactions in interstate commerce.

NSP-Minnesota is a transmission owning member of the MISO RTO and operates within the MISO RTO and MISO wholesale market. NSP-Minnesota makes wholesale sales in other RTO markets at market-based rates. NSP-Minnesota and NSP-Wisconsin also make wholesale electric sales at market-based prices to customers outside of their balancing authority as jointly authorized by the FERC.

Fuel, Purchased Energy and Conservation Cost-Recovery Mechanisms —

- *CIP rider* — Recovers the costs of conservation and demand-side management programs.
- *EIR* — Recovers the costs of environmental improvement projects.
- *RDF* — Allocates money collected from retail customers to support emerging renewable energy projects and technologies.
- *RES* — Recovers the cost of renewable generation in Minnesota.
- *RER* — Recovers the cost of renewable generation in North Dakota.
- *SEP* — Recovers costs related to various energy policies approved by the Minnesota legislature.
- *TCR* — Recovers costs associated with investments in electric transmission and distribution grid modernization costs.
- *Infrastructure rider* — Recovers costs for investments in generation and incremental property taxes in South Dakota.

NSP-Minnesota's retail electric rates in Minnesota, North Dakota and South Dakota include a FCA for monthly billing adjustments to recover changes in prudently incurred costs of fuel related items and purchased energy. Capacity costs are recovered through base rates and are not recovered through the FCA. Costs associated with MISO are generally recovered through either the FCA or base rates.

In 2017, the MPUC voted to change the FCA process in Minnesota. Under the new process, each month utilities would collect amounts equal to the baseline cost of energy set at the start of the plan year (base would be reset annually). Monthly variations to the baseline costs would be tracked and netted over a 12-month period. Utilities would issue refunds above the baseline costs, and could seek recovery of any overage. Recently, the MPUC delayed implementation until 2020.

Minnesota state law requires NSP-Minnesota to invest 2% of its state electric revenues and 0.5% of its state gas revenues in CIP. These costs are recovered through an annual cost-recovery mechanism for electric conservation and energy management program expenditures.

Energy Sources and Transmission Service Provider

NSP-Minnesota expects to use power plants, power purchases, CIP/DSM options, new generation facilities and expansion of power plants to meet its system capacity requirements.

Purchased Power — NSP-Minnesota has contracts to purchase power from other utilities and IPPs. Long-term purchased power contracts for dispatchable resources typically require a capacity charge and an energy charge. NSP-Minnesota makes short-term purchases to meet system requirements, replace company owned generation, meet operating reserve obligations or obtain energy at a lower cost.

Purchased Transmission Services — NSP-Minnesota and NSP-Wisconsin have contracts with MISO and other regional transmission service providers to deliver power and energy to their customers.

Wind Development — In 2017, the MPUC approved NSP-Minnesota's proposal to add 1,550 MW of new wind generation including ownership of 1,150 MW of wind generation.

In April 2018, the MPUC approved NSP-Minnesota's petition to build and own the Dakota Range, a 300 MW wind project in South Dakota. NSP-Minnesota's capital investment for the Dakota Range is expected to be approximately $350 million and placed in service in 2021.

In December 2018, the NDPSC approved a settlement agreement for these wind development projects.

PPA Terminations and Amendments — In June 2018, NSP-Minnesota terminated the Benson and Laurentian PPAs, and purchased the Benson biomass facility. As a result, a $103 million regulatory asset was recognized for the costs of the Benson transaction. For Laurentian, a regulatory asset of $109 million was recognized for annual payments/obligations. Regulatory approvals provide for recovery of the Benson regulatory asset over 10 years, and Laurentian termination payments as they occur (over six years). Termination of the PPAs is expected to save customers over $600 million over the next 10 years.

Jurisdictional Cost Recovery Allocation — In December 2016, NSP-Minnesota filed a resource treatment framework with the NDPSC and MPUC. The filing proposed a framework to allow NSP-Minnesota's operations in North Dakota and Minnesota to gradually become more independent of one another with respect to future generation resource selection while also identifying a path for cost sharing of current resources. NSP-Minnesota's filing identified two options: a legal separation, creating a separate North Dakota operating company; or a pseudo-separation, which maintains the current corporate structure but directly assigns the costs and benefits of each resource to the jurisdiction that supports it. Docket remains under consideration by the NDPSC.

Minnesota State ROFR Statute Complaint — In September 2017, LSP Transmission filed a complaint in the Minnesota District Court against the Minnesota Attorney General, the MPUC and the DOC. The complaint was in response to MISO assigning NSP-Minnesota and ITC Midwest, LLC to jointly own a new 345 KV transmission line from near Mankato, Minnesota to Winnebago, Minnesota. The project was estimated by MISO to cost $108 million. The project was assigned to NSP-Minnesota and ITC Midwest as the incumbent utilities, consistent with a Minnesota state ROFR statute. The complaint challenged the constitutionality of the state ROFR statute and is seeking declaratory judgment that the statute violates the Commerce Clause of the U.S. Constitution and should not be enforced. The Minnesota state agencies and NSP-Minnesota filed motions to dismiss. In June 2018, the Minnesota District Court granted the defendants' motions to dismiss with prejudice. LSP Transmission filed an appeal in July 2018. It is uncertain when a decision will be rendered.

Nuclear Power Operations and Waste Disposal

NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the PI plant. Nuclear power plant operations produce gaseous, liquid and solid radioactive wastes which are controlled by federal regulation. High-level radioactive wastes primarily include used nuclear fuel. LLW consists primarily of demineralizer resins, paper, protective clothing, rags, tools and equipment that have become contaminated through use in a plant.

NRC Regulation — The NRC regulates nuclear operations. The costs of complying with NRC requirements can affect both operating expenses and capital investments of the plants. NSP-Minnesota has obtained recovery of these compliance costs in customer rates, and expects future compliance costs will continue to be recoverable.

LLW Disposal — LLW from NSP-Minnesota's Monticello and PI nuclear plants is currently disposed at the Clive facility located in Utah and the Waste Control Specialists facility located in Texas. If off-site LLW disposal facilities become unavailable, NSP-Minnesota has storage capacity available on-site at PI and Monticello which would allow both plants to continue to operate until the end of their current licensed lives.

High-Level Radioactive Waste Disposal — The federal government has responsibility to permanently dispose domestic spent nuclear fuel and other high-level radioactive wastes. The Nuclear Waste Policy Act requires the DOE to implement a program for nuclear high-level waste management. This includes the siting, licensing, construction and operation of a repository for spent nuclear fuel from civilian nuclear power reactors and other high-level radioactive wastes at a permanent federal storage or disposal facility.

The federal government has been evaluating a nuclear geologic repository at Yucca Mountain, Nevada for many years. At this time, there are no definitive plans for a permanent federal storage site at Yucca Mountain or any other site.

Review of PI Costs — As part of NSP-Minnesota's 2016 multi-year electric rate case and IRP, the MPUC ordered an investigation into NSP-Minnesota's PI nuclear investments. The issue was resolved as part of the 2016 multi-year electric rate case settlement. In November 2018, the DOC issued a final report, in which no cost disallowances were recommended.

Nuclear Spent Fuel Storage — NSP-Minnesota has interim on-site storage for spent nuclear fuel at its Monticello and PI nuclear generating plants. Authorized storage capacity is sufficient to allow NSP-Minnesota to operate until the end of the operating licenses in 2030 for Monticello, 2033 for PI Unit 1, and 2034 for PI Unit 2. Authorizations for additional spent fuel storage capacity may be required at each site to support either continued operation or decommissioning if the federal government does not commence storage operations.

In 2013, NSP-Minnesota's Monticello nuclear generating plant loaded and placed five storage canisters (canisters #11-15) in the ISFSI and a sixth canister (canister #16) was loaded but remained in the plant pending resolution of weld inspection issues. Successful pressure and leak testing demonstrated the safety and integrity of all six canisters involved. NSP-Minnesota took several actions to assure compliance with the NRC's regulations and Monticello's storage license. The NRC has approved NSP-Minnesota's compliance plan for all canisters.

NSP-Minnesota intends to seek recovery of these costs in a future regulatory proceeding. No public safety issues have been raised, or are believed to exist, in this matter.

See Note 10 to the consolidated financial statements for further information.

Wholesale and Commodity Marketing Operations

NSP-Minnesota conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy, ancillary services and energy-related products. NSP-Minnesota uses physical and financial instruments to minimize commodity price and credit risk and hedge sales and purchases. NSP-Minnesota also engages in trading activity unrelated to hedging and sharing of any margins is determined through state regulatory proceedings as well as the operation of the FERC approved joint operating agreement. NSP-Minnesota does not serve any wholesale requirements customers at cost-based regulated rates.

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NATURAL GAS UTILITY OPERATIONS

Natural Gas Operating Statistics

	Year Ended Dec. 31		
	2018	2017	2016
Natural gas deliveries (Thousands of MMBtu)			
Residential	43,876	38,365	35,592
C&I	45,909	41,047	37,824
Total retail	89,785	79,412	73,416
Transportation and other	13,101	13,109	11,189
Total deliveries	102,886	92,521	84,605
Number of customers at end of period			
Residential	475,441	470,255	465,745
C&I	44,217	43,859	43,553
Total retail	519,658	514,114	509,298
Transportation and other	26	26	25
Total customers	519,684	514,140	509,323
Natural gas revenues (Millions of Dollars)			
Residential	$ 320.0	$ 287.5	$ 261.6
C&I	248.8	221.6	194.0
Total retail	568.8	509.1	455.6
Transportation and other	14.3	22.8	11.8
Total natural gas revenues	$ 583.1	$ 531.9	$ 467.4
MMBtu sales per retail customer	172.78	154.46	144.15
Revenue per retail customer	$ 1,095	$ 990	$ 895
Residential revenue per MMBtu	7.29	7.49	7.35
C&I revenue per MMBtu	5.42	5.40	5.13
Transportation and other revenue per MMBtu	1.09	1.74	1.05

Capability and Demand

Natural gas supply requirements are categorized as firm or interruptible (customers with an alternate energy supply).

Maximum daily send-out (firm and interruptible) and occurrence date:

2018		2017	
MMBtu	Date	MMBtu	Date
786,751 (a)	Jan. 12	893,062	Dec. 26

(a) Decrease in MMBtu output due to milder winter temperatures in 2018.

Natural gas is purchased from independent suppliers, generally based on market indices that reflect current prices. The natural gas is delivered under transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of 645,171 MMBtu per day.

NSP-Minnesota contracts with providers of underground natural gas storage services. Agreements provided storage of winter natural gas requirements and peak day firm requirements of 24% and 29% in 2018, respectively.

Natural Gas Supply and Costs

NSP-Minnesota actively seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio which provides increased flexibility, decreased interruption and financial risk and economical rates. In addition, NSP-Minnesota conducts natural gas price hedging activities approved by their respective state commissions.

Average delivered cost per MMBtu of natural gas for regulated retail distribution was $4.03 and $3.89 in 2018 and 2017, respectively.

NSP-Minnesota has natural gas supply, transportation, and storage agreements that include obligations for purchase and/or delivery of specified volumes or to make payments in lieu of delivery. As of Dec. 31, 2018, NSP-Minnesota was committed to approximately $437 million of obligations under contracts, which expire in various years from 2019 - 2033.

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — Retail rates, services and other aspects of NSP-Minnesota's retail natural gas operations are regulated by the MPUC and NDPSC. The MPUC has regulatory authority over security issuances, certain property transfers, mergers with other utilities and transactions between NSP-Minnesota and its affiliates. The MPUC reviews and approves NSP-Minnesota's natural gas supply plans for meeting future energy needs. NSP-Minnesota is subject to the jurisdiction of the FERC with respect to certain natural gas transactions in interstate commerce. NSP-Minnesota is also subject to the DOT, Minnesota Office of Pipeline Safety, NDPSC and SDPUC for pipeline safety compliance.

Purchased Gas and Conservation Cost-Recovery Mechanisms — NSP-Minnesota's retail natural gas rates for Minnesota and North Dakota include a PGA clause that provides for prospective monthly rate adjustments to reflect the forecasted cost of purchased natural gas, transportation and storage service. The annual difference between the natural gas cost revenues collected through PGA rates and the actual natural gas costs is collected or refunded over the subsequent 12-month period.

NSP-Minnesota also recovers costs associated with transmission and distribution pipeline integrity management programs through its GUIC rider. Costs recoverable under the GUIC rider include funding for pipeline assessments as well as deferred costs from NSP-Minnesota's existing sewer separation and pipeline integrity management programs.

GENERAL

Seasonality

Demand for electric power and natural gas is affected by seasonal differences in the weather. In general, peak sales of electricity occur in the summer months, and peak sales of natural gas occur in the winter months. As a result, the overall operating results may fluctuate substantially on a seasonal basis. Additionally, NSP-Minnesota's operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer.

See Item 7 for further information.

Competition

NSP-Minnesota is a vertically integrated utility, subject to traditional cost-of-service regulation by state public utilities commissions. NSP-Minnesota is subject to public policies that promote competition and development of energy markets. NSP-Minnesota's industrial and large commercial customers have the ability to generate their own electricity. In addition, customers may have the option of substituting other fuels or relocating their facilities to a lower cost region.

Customers have the opportunity to supply their own power with distributed generation including, but not limited to, solar generation and in most jurisdictions can currently avoid paying for most of the fixed production, transmission and distribution costs incurred to serve them. Several states, including Minnesota, have policies designed to promote the development of solar and other distributed energy resources through incentive policies; with these incentives and federal tax subsidies, distributed generating resources are potential competitors to NSP-Minnesota's electric service business.

The FERC has continued to promote competitive wholesale markets through open access transmission and other means. As a result, NSP-Minnesota and its wholesale customers can purchase generation resources from competing wholesale suppliers and use the transmission systems of Xcel Energy Inc.'s utility subsidiaries on a comparable basis to serve their native load.

FERC Order No. 1000 seeks to establish competition for construction and operation of certain new electric transmission facilities. State utilities commissions have also created resource planning programs that promote competition for electricity generation resources used to provide service to retail customers.

NSP-Minnesota has franchise agreements with cities subject to periodic renewal, however, a city could seek alternative means to access electric power or gas, such as municipalization.

While facing these challenges, NSP-Minnesota believes its rates and services are competitive with the alternatives currently available.

ENVIRONMENTAL MATTERS

NSP-Minnesota's facilities are regulated by federal and state environmental agencies that have jurisdiction over air emissions, water quality, wastewater discharges, solid wastes and hazardous substances. Various company activities require registrations, permits, licenses, inspections and approvals from these agencies. NSP-Minnesota has received all necessary authorizations for the construction and continued operation of its generation, transmission and distribution systems.

NSP-Minnesota's facilities have been designed and constructed to operate in compliance with applicable environmental standards and related monitoring and reporting requirements. However, it is not possible to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of changes to environmental regulations, interpretations or enforcement policies or what effect future laws or regulations may have upon NSP-Minnesota's operations. NSP-Minnesota will likely be required to incur capital expenditures in the future to comply with requirements for remediation of MGP and other legacy sites. The scope and timing of these expenditures cannot be determined until more information is obtained regarding the need for remediation at legacy sites.

NSP-Minnesota must comply with emission budgets that require the purchase of emission allowances from other utilities.

There are significant present and future environmental regulations to encourage use of clean energy technologies and regulate emissions of GHGs. NSP-Minnesota has undertaken numerous initiatives to meet current requirements and prepare for potential future regulations, reduce GHG emissions and respond to state renewable and energy efficiency goals. If future environmental regulations do not provide credit for the investments NSP-Minnesota has already made or if they require additional initiatives or emission reductions, substantial costs may be incurred.

The EPA , as an alternative to the CPP, has proposed a new regulation that, if adopted, would require implementation of heat rate improvement projects at our coal-fired power plants. It is not known what those costs might be until a final rule is adopted and state plans are developed to implement a final regulation. NSP-Minnesota believes, based on prior state commission practice, the cost of these initiatives or replacement generation would be recoverable through rates.

NSP-Minnesota is committed to addressing climate change and potential climate change regulation through efforts to reduce its GHG emissions in a balanced, cost-effective manner. Starting in 2011, NSP-Minnesota began reporting GHG emissions under the EPA's mandatory GHG Reporting Program.

EMPLOYEES

As of Dec. 31, 2018, NSP-Minnesota had 3,271 full-time employees and seven part-time employees, of which 2,064 were covered under collective-bargaining agreements.

Item 1A — Risk Factors

Xcel Energy, which includes NSP-Minnesota, is subject to a variety of risks, many of which are beyond our control. Risks that may adversely affect the business, financial condition, results of operations or cash flows are described below. These risks should be carefully considered together with the other information set forth in this report and future reports that Xcel Energy files with the SEC.

Oversight of Risk and Related Processes

A key accountability of the Board of Directors is the oversight of material risk, and our Board of Directors employs an effective process for doing so. Management and the Board of Directors have responsibility for overseeing the identification and mitigation of key risks.

Management identifies and analyzes risks to determine materiality and other attributes such as timing, probability and controllability. Identification and analysis occurs formally through a key risk assessment conducted by senior management, the financial disclosure process, hazard risk management procedures and internal auditing and compliance with financial and operational controls.

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Management also identifies and analyzes risk through its business planning process and development of goals and key performance indicators, which include risk identification to determine barriers to implementing NSP-Minnesota's strategy. The business planning process also identifies areas in which there is a potential for a business area to assume inappropriate risk to meet goals, and determines how to prevent inappropriate risk-taking.

At a threshold level, NSP-Minnesota has a robust compliance program and promotes a culture of compliance, including tone at the top. The process for risk mitigation includes adherence to our code of conduct and compliance policies, operation of formal risk management structures and overall business management to mitigate the risks inherent in the implementation of strategy. Building on this culture of compliance, management further mitigates risks through formal risk management structures, including management councils, risk committees and services of corporate areas such as internal audit, corporate controller and legal.

Management communicates regularly with the Board of Directors and key stakeholders regarding risk. Senior management presents and communicates a periodic risk assessment to the Board of Directors which provides information on the risks management believes are material, including the earnings impact, timing, likelihood and controllability. Oversight of cybersecurity risks by the Operations, Nuclear, Environmental and Safety Committee includes receiving independent outside assessments of cybersecurity maturity and assessment of plans.

Overall, the Board of Directors approaches oversight, management and mitigation of risk as an integral and continuous part of its governance of NSP-Minnesota. Processes are in place to ensure appropriate risk oversight, as well as identification and consideration of new risks. The Board of Directors regularly reviews management's key risk assessment informed by these processes, and analyzes areas of existing and future risks and opportunities.

Risks Associated with Our Business

Operational Risks

Our natural gas and electric transmission and distribution operations involve numerous risks that may result in accidents and other operating risks and costs.

Our natural gas transmission and distribution activities include inherent hazards and operating risks, such as leaks, explosions, outages and mechanical problems.

Our electric transmission and distribution activities also include inherent hazards and operating risks such as contact, fire and outages which could cause substantial financial losses. These natural gas and electric risks could result in loss of life, significant property damage, environmental pollution, impairment of our operations and substantial losses. We maintain insurance against some, but not all, of these risks and losses. The occurrence of these events, if not fully covered by insurance, could have a material effect on our financial condition, results of operations and cash flows.

Additionally, for natural gas costs that may be required in order to comply with potential new regulations, including the Pipeline Safety Act, could be significant.

The Pipeline Safety Act requires verification of pipeline infrastructure records by pipeline owners and operators to confirm the maximum allowable operating pressure of lines located in high consequence areas or more-densely populated areas. We have programs in place to comply with the Pipeline Safety Act and for systematic infrastructure monitoring and renewal over time. A significant incident could increase regulatory scrutiny and result in penalties and higher costs of operations.

The PHMSA is responsible for administering the DOT's national regulatory program to assure the safe transportation of natural gas, petroleum and other hazardous materials by pipelines. The PHMSA continues to develop regulations and other approaches to risk management to assure safety in design, construction, testing, operation, maintenance, and emergency response of natural gas pipeline infrastructure.

Our utility operations are subject to long-term planning risks.

Most electric utility investments are planned to be used for decades. Transmission and generation investments typically have long lead times and are planned well in advance of when they are brought in-service subject to long-term resource plans. These plans are based on numerous assumptions such as: sales growth, customer usage, commodity prices, economic activity, costs, regulatory mechanisms, customer behavior, available technology and public policy.

The electric utility sector is undergoing a period of significant change. For example, increases in appliance, lighting and energy efficiency, wider adoption and lower cost of renewable generation and distributed generation, shifts away from coal generation to decrease CO_2 emissions and increasing use of natural gas in electric generation driven by lower natural gas prices. Customer adoption of these technologies and increased energy efficiency could result in excess transmission and generation resources as well as stranded costs if NSP-Minnesota is not able to fully recover the costs and investments. These changes also introduce additional uncertainty into long-term planning which gives rise to a risk that the magnitude and timing of resource additions and growth in customer demand may not coincide, and that the preference for the types of additions may change from planning to execution. In addition, we are subject to longer-term availability of the natural resource inputs such as coal, natural gas, uranium and water to cool our facilities. Lack of availability of these resources could jeopardize long-term operations of our facilities or make them uneconomic to operate.

Changing customer expectations and technologies are requiring significant investments in advanced grid infrastructure. This increases the exposure to potential outdating of technologies and resultant risks. The inability of coal mining companies to attract capital could disrupt longer-term supplies. Decreasing use per customer driven by appliance and lighting efficiency and the availability of cost-effective distributed generation places downward pressure on sales growth. This may lead to under recovery of costs, excess resources to meet customer demand and increases in electric rates. Finally, multiple states may not agree as to the appropriate resource mix and the differing views may lead to costs incurred to comply with one jurisdiction that are not recoverable across all of the jurisdictions served by the same assets.

We are subject to the risks of nuclear generation.

Our two nuclear stations, PI and Monticello, subject us to the risks of nuclear generation, which include:

- Risks associated with use of radioactive material in the production of energy, the management, handling, storage and disposal of radioactive materials;
- Limitations on insurance available to cover losses that might arise in connection with nuclear operations, as well as obligations to contribute to an insurance pool in the event of damages at a covered U.S. reactor; and,
- Uncertainties with the technological and financial aspects of decommissioning nuclear plants. For example, assumptions regarding decommissioning costs may change based on economic conditions and changes in the expected life of the asset may cause our funding obligations to change.

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The NRC has authority to impose licensing and safety-related requirements for the operation of nuclear generation facilities. The NRC has the authority to impose fines and/or shut down a unit until compliance is achieved. Revised NRC safety requirements could necessitate substantial capital expenditures or an increase in operating expenses. In addition, the Institute for Nuclear Power Operations reviews our nuclear operations and nuclear generation facilities. Compliance with the Institute for Nuclear Power Operations' recommendations could result in substantial capital expenditures or a substantial increase in operating expenses.

If an incident did occur, it could have a material effect on our results of operations, financial condition or cash flows. Furthermore, the non-compliance or the occurrence of a serious incident at other nuclear facilities could result in increased regulation of the industry, which may increase our compliance costs.

NSP-Wisconsin's production and transmission system is operated on an integrated basis with our production and transmission system, and NSP-Wisconsin may be subject to risks associated with our nuclear generation.

We are subject to commodity risks and other risks associated with energy markets and energy production.

If fuel costs increase, customer demand could decline and bad debt expense may rise, which could have a material impact on our results of operations. While we have fuel clause recovery mechanisms, higher fuel costs could significantly impact our results of operations if costs are not recovered. Delays in the timing of the collection of fuel cost recoveries could impact our cash flows. Low fuel costs have a positive impact on sales, however low oil and natural gas prices could negatively impact oil and gas production activities and subsequently our sales volumes and revenue.

A significant disruption in supply could cause us to seek alternative supply services at potentially higher costs or suffer increased liability for unfulfilled contractual obligations. Significantly higher energy or fuel costs relative to sales commitments have a negative impact on our cash flows and potentially result in economic losses. Potential market supply shortages may not be fully resolved through alternative supply sources and could cause disruptions in our ability to provide electric and/or natural gas services to our customers. Failure to provide service due to disruptions may also result in fines, penalties or cost disallowances through the regulatory process.

We also engage in wholesale sales and purchases of electric capacity, energy and energy-related products as well as natural gas. In many markets, emission allowances and/or RECs are also needed to comply with various statutes and commission rulings. As a result we are subject to market supply and commodity price risk. Commodity price changes can affect the value of our commodity trading derivatives. We mark certain derivatives to estimated fair market value on a daily basis. Actual settlements can vary significantly from estimated fair values recorded and significant changes from the assumptions underlying our fair value estimates could cause earnings variability.

As we are a subsidiary of Xcel Energy Inc., we may be negatively affected by events impacting the credit or liquidity of Xcel Energy Inc. and its affiliates.

If Xcel Energy Inc. were to become obligated to make payments under various guarantees and bond indemnities or to fund its other contingent liabilities, or if either Standard & Poor's or Moody's were to downgrade Xcel Energy Inc.'s credit rating below investment grade, Xcel Energy Inc. may be required to provide credit enhancements in the form of cash collateral, letters of credit or other security to satisfy part or potentially all of these exposures.

If either Standard & Poor's or Moody's were to downgrade Xcel Energy Inc.'s debt securities below investment grade, it would increase Xcel Energy Inc.'s cost of capital and restrict its access to the capital markets. This could limit Xcel Energy Inc.'s ability to contribute equity or make loans to us, or may cause Xcel Energy Inc. to seek additional or accelerated funding from us in the form of dividends. If such event were to occur, we may need to seek alternative sources of funds to meet our cash needs.

As of Dec. 31, 2018, Xcel Energy Inc. and its utility subsidiaries had approximately $15.8 billion of long-term debt and $1.4 billion of short-term debt and current maturities. Xcel Energy Inc. provides various guarantees and bond indemnities supporting some of its subsidiaries by guaranteeing the payment or performance by these subsidiaries for specified agreements or transactions.

Xcel Energy also has other contingent liabilities resulting from various tax disputes and other matters. Xcel Energy Inc.'s exposure under the guarantees is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. The majority of Xcel Energy Inc.'s guarantees limit its exposure to a maximum amount that is stated in the guarantees. As of Dec. 31, 2018, Xcel Energy had guarantees outstanding with a maximum stated amount of approximately $17.8 million and immaterial exposure. Xcel Energy also had additional guarantees of $51.1 million at Dec. 31, 2018 for performance and payment of surety bonds for the benefit of itself and its subsidiaries, with total exposure that cannot be estimated at this time. If Xcel Energy Inc. were to become obligated to make payments under these guarantees and bond indemnities or become obligated to fund other contingent liabilities, it could limit Xcel Energy Inc.'s ability to contribute equity or make loans to us, or may cause Xcel Energy Inc. to seek additional or accelerated funding from us in the form of dividends. If such event were to occur, we may need to seek alternative sources of funds to meet our cash needs.

We are a wholly owned subsidiary of Xcel Energy Inc. Xcel Energy Inc. can exercise substantial control over our dividend policy and business and operations and may exercise that control in a manner that may be perceived to be adverse to our interests.

All of the members of our Board of Directors, as well as many of our executive officers, are officers of Xcel Energy Inc. Our Board makes determinations with respect to a number of significant corporate events, including the payment of our dividends.

We have historically paid quarterly dividends to Xcel Energy Inc. In 2018, 2017 and 2016 we paid $456.3 million, $506.6 million and $395.9 million of dividends to Xcel Energy Inc., respectively. If Xcel Energy Inc.'s cash requirements increase, our Board of Directors could decide to increase the dividends we pay to Xcel Energy Inc. to help support Xcel Energy Inc.'s cash needs. This could adversely affect our liquidity. The most restrictive dividend limitation for NSP-Minnesota is imposed by our state regulatory commissions. State regulatory commissions indirectly limit the amount of dividends NSP-Minnesota can pay to Xcel Energy Inc., by requiring a minimum equity-to-total capitalization ratio. See Note 5 to the consolidated financial statements for further information.

Financial Risks

Our profitability depends on our ability to recover costs from our customers and changes in regulation may impair our ability to recover costs from our customers.

We are subject to comprehensive regulation by federal and state utility regulatory agencies, including siting and construction of facilities, customer service and the rates that we can charge customers.

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The profitability of our operations is dependent on our ability to recover the costs of providing energy and utility services and earn a return on our capital investment. Our rates are generally regulated and based on an analysis of our costs incurred in a test year. We are subject to both future and historical test years depending upon the regulatory jurisdiction. Thus, the rates we are allowed to charge may or may not match our costs at any given time. Rate regulation is premised on providing an opportunity to earn a reasonable rate of return on invested capital. In a continued low interest rate environment there has been pressure pushing down ROE. There can also be no assurance that our regulatory commissions will judge all of our costs to be prudent, which could result in disallowances, or that the regulatory process will always result in rates that will produce full recovery. Changes in the long-term cost-effectiveness or changes to the operating conditions of our assets may result in early retirements of utility facilities and while regulation typically provides relief for these types of changes, there is no assurance that regulators would allow full recovery of all remaining costs leaving all or a portion of these asset costs stranded. Higher than expected inflation or tariffs may increase costs of construction and operations. Rising fuel costs could increase the risk that we will not be able to fully recover our fuel costs from our customers. Furthermore, there could be changes in the regulatory environment that would impair our ability to recover costs historically collected from our customers, or these factors could cause us to exceed commitments made regarding cost caps and result in less than full recovery. Overall, management currently believes prudently incurred costs are recoverable given the existing regulatory mechanisms in place.

Adverse regulatory rulings or the imposition of additional regulations could have an adverse impact on our results of operations and materially affect our ability to meet our financial obligations, including debt payments.

Any reductions in our credit ratings could increase our financing costs and the cost of maintaining certain contractual relationships.

We cannot be assured that our current ratings will remain in effect, or that a rating will not be lowered or withdrawn by a rating agency. Significant events including a disallowance of costs, significantly lower returns on equity or equity ratios or impacts of tax policy changes may impact our cash flows and credit metrics, potentially resulting in a change in our credit ratings. In addition, our credit ratings may change as a result of the differing methodologies or change in the methodologies used by the various rating agencies. Any downgrade could lead to higher borrowing costs and could impact our ability to access capital markets.

Also, we may enter into contracts that require the posting of collateral or settlement of applicable contracts if credit ratings fall below investment grade.

We are subject to capital market and interest rate risks.

Utility operations require significant capital investment. As a result, we frequently need to access capital markets. Any disruption in capital markets could have a material impact on our ability to fund our operations. Capital markets are global and impacted by issues and events throughout the world. Capital market disruption events and financial market distress could prevent us from issuing short-term commercial paper, issuing new securities or cause us to issue securities with unfavorable terms and conditions, such as higher interest rates.

Higher interest rates on short-term borrowings with variable interest rates could also have an adverse effect on our operating results. Changes in interest rates may also impact the fair value of the debt securities in the nuclear decommissioning and/or pension funds, as well as our ability to earn a return on short-term investments of excess cash.

We are subject to credit risks.

Credit risk includes the risk that our customers will not pay their bills, which may lead to a reduction in liquidity and an increase in bad debt expense. Credit risk is comprised of numerous factors including the price of products and services provided, the overall economy and local economies in the geographic areas we serve, including local unemployment rates.

Credit risk also includes the risk that various counterparties that owe us money or product will become insolvent and/or breach their obligations. Should the counterparties fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected and incur losses.

We may at times have direct credit exposure in our short-term wholesale and commodity trading activity to financial institutions trading for their own accounts or issuing collateral support on behalf of other counterparties. We may also have some indirect credit exposure due to participation in organized markets, such as Southwest Power Pool, Inc., PJM Interconnection, LLC, MISO and Electric Reliability Council of Texas, in which any credit losses are socialized to all market participants.

We have additional indirect credit exposures to financial institutions in the form of letters of credit provided as security by power suppliers under various purchased power contracts. If any of the credit ratings of the letter of credit issuers were to drop below investment grade, the supplier would need to replace that security with an acceptable substitute. If the security were not replaced, the party could be in default under the contract.

Increasing costs of our defined benefit retirement plans and employee benefits may adversely affect our results of operations, financial condition or cash flows.

We have defined benefit pension and postretirement plans that cover most of our employees. Assumptions related to future costs, return on investments, interest rates and other actuarial assumptions have a significant impact on our funding requirements related to these plans. Estimates and assumptions may change. In addition, the Pension Protection Act changed the minimum funding requirements for defined benefit pension plans. Therefore, our funding requirements and related contributions may change in the future.

Also, the payout of a significant percentage of pension plan liabilities in a single year due to high retirements or employees leaving NSP-Minnesota could trigger settlement accounting and could require NSP-Minnesota to recognize incremental pension expense related to unrecognized plan losses in the year liabilities are paid.

Increasing costs associated with health care plans may adversely affect our results of operations.

Our self-insured costs of health care benefits for eligible employees have increased in recent years. Increasing levels of large individual health care claims and overall health care claims could have an adverse impact on our operating results, financial condition and cash flows. Changes in industry standards utilized in key assumptions (e.g., mortality tables) could have a significant impact on future liabilities and benefit costs. Legislation related to health care could also significantly change our benefit programs and costs.

Federal tax law may significantly impact our business.

NSP-Minnesota collects through regulated rates estimated federal, state and local tax payments. Changes to federal tax law may benefit or adversely affect our earnings and customer costs. Changes to tax depreciable lives and the value of various tax credits may change the economics of resources and our resource selections.

There could be timing delays before regulated rates provide for realization of the tax changes in revenues. In addition, certain IRS tax policies such as the requirement to utilize normalization may impact our ability to economically deliver certain types of resources relative to market prices.

Macroeconomic Risks

Economic conditions impact our business.

Our operations are affected by local, national and worldwide economic conditions. Growth in customers and sales are correlated with economic conditions.

Economic conditions may be impacted by insufficient financial sector liquidity leading to potential increased unemployment, which may impact customers' ability to pay timely, increase customer bankruptcies, and may lead to additional bad debt expense.

Further, worldwide economic activity impacts the demand for basic commodities necessary for utility infrastructure, which may impact our ability to acquire sufficient supplies. We operate in a capital intensive industry and federal policy on trade could significantly impact the cost of materials we use. We could be at risk for higher costs for materials and our workforce. There may be delays before these additional costs can be recovered in rates.

Our operations could be impacted by war, acts of terrorism, and threats of terrorism or disruptions due to events.

Our generation plants, fuel storage facilities, transmission and distribution facilities and information and control systems may be targets of terrorist activities. Any disruption could impact operations or result in a decrease in revenues and additional costs to repair and insure our assets. These disruptions could have a material impact on our results of operations, financial condition or cash flows. The potential for terrorism has subjected our operations to increased risks and could have a material effect on our business. We have already incurred increased costs for security and capital expenditures in response to these risks.

The insurance industry has also been affected by these events and the availability of insurance may decrease. In addition, insurance may have higher deductibles, higher premiums and more restrictive policy terms.

A disruption of the regional electric transmission grid, interstate natural gas pipeline infrastructure or other fuel sources, could negatively impact our business, our brand and reputation.

Because our facilities are part of an interconnected system, we face the risk of possible loss of business due to a disruption caused by the actions of a neighboring utility or an event (e.g., severe storm, severe temperature extremes, wildfires, generator or transmission facility outage, pipeline rupture, railroad disruption, operator error, sudden and significant increase or decrease in wind generation or a disruption of work force) within our operating systems or on a neighboring system. Any such disruption could result in a significant decrease in revenues and significant additional costs to repair assets, which could have a material impact on our results of operations, financial condition or cash flows.

A cyber incident or security breach could have a material effect on our business.

We operate in an industry that requires the continued operation of sophisticated information technology, control systems and network infrastructure. In addition, we use our systems and infrastructure to create, collect, use, disclose, store, dispose of and otherwise process sensitive information, including company data, customer energy usage data, and personal information regarding customers, employees and their dependents, contractors and other individuals.

Our generation, transmission, distribution and fuel storage facilities, information technology systems and other infrastructure or physical assets, as well as information processed in our systems (e.g., information regarding our customers, employees, operations, infrastructure and assets) could be affected by cyber security incidents, including those caused by human error.

Our industry has begun to see an increased volume and sophistication of cyber security incidents from international activist organizations, Nation States and individuals. Cyber security incidents could harm our businesses by limiting our generating, transmitting and distributing capabilities, delaying our development and construction of new facilities or capital improvement projects to existing facilities, disrupting our customer operations or causing the release of customer information, all of which could expose us to liability.

Our generation, transmission systems and natural gas pipelines are part of an interconnected system. Therefore, a disruption caused by the impact of a cyber security incident of the regional electric transmission grid, natural gas pipeline infrastructure or other fuel sources of our third party service providers' operations, could also negatively impact our business.

Our supply chain for procurement of digital equipment may expose software or hardware to these risks and could result in a breach or significant costs of remediation. In addition, such an event would likely receive federal and state regulatory scrutiny. We are unable to quantify the potential impact of cyber security threats or subsequent related actions. These potential cyber security incidents and regulatory action could result in a material decrease in revenues and may cause significant additional costs (e.g., penalties, third party claims, repairs, insurance or compliance) and potentially disrupt our supply and markets for natural gas, oil and other fuels.

We maintain security measures to protect our information technology and control systems, network infrastructure and other assets. However, these assets and the information they process may be vulnerable to cyber security incidents, including the resulting disability, or failures of assets or unauthorized access to assets or information. If our technology systems or those of our third-party service providers were to fail or be breached, we may be unable to fulfill critical business functions. We are unable to quantify the potential impact of cyber security incidents on our business, our brand, and our reputation. The cyber security threat is dynamic and evolves continually, and our efforts to prioritize network monitoring may not be effective given the constant changes to threat vulnerability.

Our operating results may fluctuate on a seasonal and quarterly basis and can be adversely affected by milder weather.

Our electric and natural gas utility businesses are seasonal, and weather patterns can have a material impact on our operating performance. Demand for electricity is often greater in the summer and winter months associated with cooling and heating. Because natural gas is heavily used for residential and commercial heating, the demand depends heavily upon weather patterns. A significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. Unusually mild winters and summers could have an adverse effect on our financial condition, results of operations, or cash flows.

Our operations use third party contractors in addition to employees to perform periodic and on-going work.

We rely on third party contractors to perform work for operations, maintenance and construction. We have contractual arrangements with these contractors which typically include performance standards, progress payments, insurance requirements and security for performance.

Cyber security breaches have at times exploited third party equipment or software in order to gain access. Poor vendor performance could impact on going operations, restoration operations, our reputation and could introduce financial risk or risks of fines.

Public Policy Risks

We may be subject to legislative and regulatory responses to climate change, with which compliance could be difficult and costly.

Legislative and regulatory responses related to climate change and new interpretations of existing laws create financial risk as our facilities may be subject to additional regulation at either the state or federal level in the future. Such regulations could impose substantial costs on our system.

We may be subject to climate change lawsuits. An adverse outcome could require substantial capital expenditures and could possibly require payment of substantial penalties or damages. Defense costs associated with such litigation can also be significant. Such payments or expenditures could affect results of operations, financial condition or cash flows if such costs are not recovered through regulated rates.

Although the United States has not adopted any international or federal GHG emission reduction targets, many states and localities may continue to pursue climate policies in the absence of federal mandates. All of the steps that NSP-Minnesota has taken to date to reduce GHG emissions, including energy efficiency measures, adding renewable generation or retiring or converting coal plants to natural gas, occurred under state-endorsed resource plans, renewable energy standards and other state policies. While those actions likely would have put NSP-Minnesota in a good position to meet federal or international standards being discussed, the lack of federal action does not adversely impact these state-endorsed actions and plans.

If our regulators do not allow us to recover all or a part of the cost of capital investment or the O&M costs incurred to comply with the mandates, it could have a material effect on our results of operations, financial condition or cash flows.

Increased risks of regulatory penalties could negatively impact our business.

The Energy Act increased civil penalty authority for violation of FERC statutes, rules and orders. The FERC can impose penalties of up to $1.3 million per violation per day, particularly as it relates to energy trading activities for both electricity and natural gas. In addition, NERC electric reliability standards and critical infrastructure protection requirements are mandatory and subject to potential financial penalties. Additionally, the PHMSA, Occupational Safety and Health Administration and other federal agencies have penalty authority. In the event of serious incidents, these agencies have become more active in pursuing penalties. Some states have the authority to impose substantial penalties. If a serious reliability or safety incident did occur, it could have a material effect on our results of operations, financial condition or cash flows.

Environmental Risks

We are subject to environmental laws and regulations, with which compliance could be difficult and costly.

We are subject to environmental laws and regulations that affect many aspects of our operations, including air emissions, water quality, wastewater discharges and the generation, transport and disposal of solid wastes and hazardous substances. Laws and regulations require us to obtain permits, licenses, and approvals and to comply with a variety of environmental requirements.

Environmental laws and regulations can also require us to restrict or limit the output of facilities or the use of certain fuels, shift generation to lower-emitting, install pollution control equipment, clean up spills and other contamination and correct environmental hazards. Environmental regulations may also lead to shutdown of existing facilities. Failure to meet requirements of environmental mandates may result in fines or penalties. We may be required to pay all or a portion of the cost to remediate (i.e., clean-up) sites where our past activities, or the activities of other parties, caused environmental contamination.

We are subject to mandates to provide customers with clean energy, renewable energy and energy conservation offerings. It could have a material effect on our results of operations, financial condition or cash flows. If our regulators do not allow us to recover the cost of capital investment or the O&M costs incurred to comply with the requirements.

In addition, existing environmental laws or regulations may be revised, and new laws or regulations may be adopted. We may also incur additional unanticipated obligations or liabilities under existing environmental laws and regulations.

We are subject to physical and financial risks associated with climate change and other weather, natural disaster and resource depletion impacts.

Climate change can create physical and financial risk. Physical risks include changes in weather conditions and extreme weather events.

Our customers' energy needs vary with weather. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease. Increased energy use due to weather changes may require us to invest in generating assets, transmission and infrastructure. Decreased energy use due to weather changes may result in decreased revenues. Extreme weather conditions in general require system backup, costs, and can contribute to increased system stress, including service interruptions. Extreme weather conditions creating high energy demand may raise electricity prices, increasing the cost of energy we provide to our customers.

Severe weather impacts our service territories, primarily when thunderstorms, flooding, tornadoes, wildfires and snow or ice storms occur. To the extent the frequency of extreme weather events increases, this could increase our cost of providing service. Periods of extreme temperatures could impact our ability to meet demand. Changes in precipitation resulting in droughts or water shortages could adversely affect our operations. Drought conditions also contribute to the increase in wildfire risk from our electric generation facilities. While we carry liability insurance, given an extreme event, if NSP-Minnesota was found to be liable for wildfire damages, amounts that potentially exceed our coverage could negatively impact our results of operations, financial condition or cash flows. Drought or water depletion could adversely impact our ability to provide electricity to customers and increase the price paid for energy. We may not recover all costs related to mitigating these physical and financial risks.

Climate change may impact a region's economy, which could impact our sales and revenues. The price of energy has an impact on the economic health of our communities. The cost of additional regulatory requirements, such as regulation of GHG, could impact the availability of goods and prices charged by our suppliers which would normally be borne by consumers through higher prices for energy and purchased goods. To the extent financial markets view climate change and emissions of GHGs as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less than ideal terms and conditions.

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Item 1B — Unresolved Staff Comments

None.

Item 2 — Properties

Virtually all of the utility plant property of NSP-Minnesota is subject to the lien of its first mortgage bond indenture.

NSP-Minnesota

Station, Location and Unit	Fuel	Installed	MW [a]	
Steam:				
A.S. King-Bayport, MN, 1 Unit	Coal	1968	511	
Sherco-Becker, MN				
Unit 1	Coal	1976	680	
Unit 2	Coal	1977	682	
Unit 3	Coal	1987	517	(b)
Monticello MN, 1 Unit	Nuclear	1971	617	
PI-Welch, MN				
Unit 1	Nuclear	1973	521	
Unit 2	Nuclear	1974	519	
Various locations, 4 Units	Wood/Refuse	Various	36	(c)
Combustion Turbine:				
Angus Anson-Sioux Falls, SD, 3 Units	Natural Gas	1994 - 2005	327	
Black Dog-Burnsville, MN, 3 Units	Natural Gas	1987 - 2002	494	(d)
Blue Lake-Shakopee, MN, 6 Units	Natural Gas	1974 - 2005	453	
High Bridge-St. Paul, MN, 3 Units	Natural Gas	2008	530	
Inver Hills-Inver Grove Heights, MN, 6 Units	Natural Gas	1972	282	
Riverside-Minneapolis, MN, 3 Units	Natural Gas	2009	454	
Various locations, 14 Units	Natural Gas	Various	67	
Wind:				
Border-Rolette County, ND, 75 Units	Wind	2015	148	(e)
Courtenay Wind, ND, 100 Units	Wind	2016	195	(e)
Grand Meadow-Mower County, MN, 67 Units	Wind	2008	101	(e)
Nobles-Nobles County, MN, 134 Units	Wind	2010	200	(e)
Pleasant Valley-Mower County, MN, 100 Units	Wind	2015	196	(e)
		Total	7,530	

(a) Summer 2018 net dependable capacity.
(b) Based on NSP-Minnesota's ownership of 59%.
(c) Refuse-derived fuel is made from municipal solid waste.
(d) Black Dog Unit 6 was commissioned and placed into operation in the third quarter of 2018.
(e) The values disclosed are the maximum generation levels for these wind units. Capacity is attainable only when wind conditions are sufficiently available (on-demand net dependable capacity is zero).

Electric utility overhead and underground transmission and distribution lines (measured in conductor miles) at Dec. 31, 2018:

Conductor Miles	
500 KV	2,917
345 KV	13,560
230 KV	2,202
161 KV	615
115 KV	7,372
Less than 115 KV	86,185

NSP-Minnesota had 348 electric utility transmission and distribution substations at Dec. 31, 2018.

Natural gas utility mains at Dec. 31, 2018:

Miles	
Transmission	90
Distribution	10,437

Item 3 — Legal Proceedings

NSP-Minnesota is involved in various litigation matters that are being defended and handled in the ordinary course of business. Assessment of whether a loss is probable or is a reasonable possibility, and whether a loss or a range of loss is estimable, often involves a series of complex judgments regarding future events. Management maintains accruals for losses that are probable of being incurred and subject to reasonable estimation. Management may be unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) damages sought are indeterminate, (2) proceedings are in the early stages or (3) matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

See Note 10 to the consolidated financial statements, Item 1 and Item 7 for further information.

Item 4 — Mine Safety Disclosures

None.

PART II

Item 5 — Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

NSP-Minnesota is a wholly owned subsidiary of Xcel Energy Inc. and there is no market for its common equity securities. See Note 5 to the consolidated financial statements for further information.

The dividends declared during 2018 and 2017 were as follows:

(Millions of Dollars)	2018	2017
First quarter	$ 84.6	$ 85.7
Second quarter	88.7	88.0
Third quarter	184.2	243.5
Fourth quarter	82.7	98.7

Item 6 — Selected Financial Data

This is omitted per conditions set forth in general instructions I(1)(a) and (b) of Form 10-K for wholly owned subsidiaries (reduced disclosure format).

Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operations

Discussion of financial condition and liquidity for NSP-Minnesota is omitted per conditions set forth in general instructions I(1)(a) and (b) of Form 10-K for wholly owned subsidiaries. It is replaced with management's narrative analysis and the results of operations for the current year as set forth in general instructions I(2)(a) of Form 10-K for wholly owned subsidiaries (reduced disclosure format).

Non-GAAP Financial Measures

The following discussion includes financial information prepared in accordance with GAAP, as well as certain non-GAAP financial measures such as, electric margin, natural gas margin, and ongoing earnings. Generally, a non-GAAP financial measure is a measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are adjusted from measures calculated and presented in accordance with GAAP. NSP-Minnesota's management uses non-GAAP measures for financial planning and analysis, for reporting of results, in determining performance-based compensation, and communicating its earnings outlook to analysts and investors. Non-GAAP financial measures are intended to supplement investors' understanding of our performance and should not be considered alternatives for financial measures presented in accordance with GAAP. These measures are discussed in more detail below and may not be comparable to other companies' similarly titled non-GAAP financial measures.

Electric and Natural Gas Margins

Electric margin is presented as electric revenues less electric fuel and purchased power expenses. Natural gas margin is presented as natural gas revenues less the cost of natural gas sold and transported. Expenses incurred for electric fuel and purchased power and the cost of natural gas are generally recovered through various regulatory recovery mechanisms. As a result, changes in these expenses are generally offset in operating revenues.

Management believes electric and natural gas margins provide the most meaningful basis for evaluating our operations because they exclude the revenue impact of fluctuations in these expenses. These margins can be reconciled to operating income, a GAAP measure, by including other operating revenues, cost of sales-other, O&M expenses, conservation and state implementation plan expenses, depreciation and amortization and taxes (other than income taxes).

Earnings Adjusted for Certain Items (Ongoing Earnings)

Ongoing earnings reflect adjustments to GAAP earnings (net income) for certain items.

Management uses these non-GAAP financial measures to evaluate and provide details of NSP-Minnesota's core earnings and underlying performance. Management believes these measurements are useful to investors to evaluate the actual and projected financial performance and contribution of NSP-Minnesota.

Results of Operations

NSP-Minnesota's net income was approximately $492.3 million for 2018, compared with approximately $490.1 million for 2017. The increase in earnings, driven by higher electric margins (before the impact of the TCJA) and natural gas margins, was offset by higher depreciation expense and O&M expenses.

Electric Margin

Electric revenues and fuel and purchased power expenses are impacted by fluctuation in the price of natural gas, coal and uranium used in the generation of electricity. However, these price fluctuations have minimal impact on electric margin due to fuel recovery mechanisms that recover fuel expenses. In addition, electric customers receive a credit for PTCs that are generated in a particular period.

Electric revenues and margin before and after the impact of the TCJA:

(Millions of Dollars)	2018	2017
Electric revenues before TCJA impact	$ 4,692.6	$ 4,541.7
Electric fuel and purchased power before TCJA impact	(1,706.6)	(1,626.9)
Electric margin before TCJA impact	$ 2,986.0	$ 2,914.8
TCJA impact (offset as a reduction in income tax)	(179.1)	—
Electric margin	$ 2,806.9	$ 2,914.8

Electric Margin

(Millions of Dollars)	2018 vs. 2017
Purchased capacity costs	$ 31.7
Retail sales growth (including Minnesota decoupling and sales true-up)	23.5
Non-fuel riders	19.0
Estimated impact of weather (net of Minnesota decoupling)	17.4
Wholesale transmission margin	8.0
Interchange agreement billings with NSP-Wisconsin	(17.9)
Conservation incentive	(8.9)
Other (net)	(1.6)
Total increase in electric margin before TCJA impact	$ 71.2
TCJA impact (offset as a reduction in income tax)	(179.1)
Total decrease in electric margin	$ (107.9)

Natural Gas Margin

Total natural gas expense varies with changing sales and the cost of natural gas. However, fluctuations in the cost of natural gas have minimal impact on natural gas margin due to natural gas cost recovery mechanisms.

Natural gas revenues and margin before and after the impact of the TCJA:

(Millions of Dollars)	2018	2017
Natural gas revenues before TCJA impact	$ 590.0	$ 531.9
Cost of natural gas sold and transported	(345.1)	(301.8)
Natural gas margin before TCJA impact	$ 244.9	$ 230.1
TCJA impact (offset as a reduction in income tax)	(6.9)	—
Natural gas margin	$ 238.0	$ 230.1

Natural Gas Margin

(Millions of Dollars)	2018 vs. 2017
Estimated impact of weather	$ 11.8
Sales growth	2.6
Other (net)	0.4
Total increase in natural gas margin before TCJA impact	$ 14.8
TCJA impact (offset as a reduction in income tax)	(6.9)
Total increase in natural gas margin	$ 7.9

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses increased $25.0 million, or 2.1%, for 2018. Significant changes are summarized below:

(Millions of Dollars)	2018 vs. 2017
Business systems and contract labor	$ 16.5
Plant generation costs	11.4
Distribution costs	5.4
Nuclear plant operations and amortization	(9.7)
Other (net)	1.4
Total increase in O&M expenses	$ 25.0

- Business systems and contract labor costs increased due to growing network and storage needs, cybersecurity, initiatives to support our customer strategy, and initiatives to improve business processes;
- Plant generation costs increased primarily due to the timing of planned maintenance and overhauls at certain generation facilities;
- Distribution costs reflect higher maintenance expenses, including vegetation management; and
- Nuclear plant operations and amortization are lower largely reflecting savings initiatives and reduced refueling outage costs.

Conservation Program Expenses — Conservation program expenses decreased $2.1 million, or 1.7%, for 2018. The decrease was due to lower recovery rates, partially offset by additional customer participation in electric conservation programs.

Conservation expenses are generally recovered concurrently through riders and base rates. Timing of recovery may not correspond to the period in which costs were incurred.

Depreciation and Amortization — Depreciation and amortization expense increased $41.0 million, or 5.9%, for 2018. The increase was primarily driven by capital expenditures due to planned system investments and amortization of certain regulatory assets.

Income Taxes — Income tax expense decreased $172.5 million for 2018 compared with the same period in 2017. The decrease in income tax expense was primarily due to a lower federal tax rate due to the TCJA, lower pretax earnings, a one-time, non-cash, income tax expense related to the impacts of tax reform in 2017, and an increase in plant-related regulatory differences related to ARAM; partially offset by a net tax benefit related to the resolution of appeals/audits in 2017 and a decrease in wind production tax credits.

The ETR was 5.2% for 2018 compared with 29.0% for 2017. The lower ETR in 2018 was primarily due to the adjustments referenced above. The wind PTCs flow back to customers through NSP-Minnesota's fuel clause and riders.

Regulation

FERC and State Regulation — The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, hydro facility licensing, natural gas transportation, asset transactions and mergers, accounting practices and certain other activities of NSP-Minnesota, including enforcement of NERC mandatory electric reliability standards. State and local agencies have jurisdiction over many of NSP-Minnesota's activities, including regulation of retail rates and environmental matters.

Xcel Energy, which includes NSP-Minnesota, attempts to mitigate the risk of regulatory penalties through formal training on prohibited practices and a compliance function that reviews interaction with the markets under FERC and Commodity Futures Trading Commission jurisdictions. Public campaigns are conducted to raise awareness of the public safety issues of interacting with our electric systems. While programs to comply with regulatory requirements are in place, there is no guarantee the compliance programs or other measures will be sufficient to ensure against violations. Decisions by these regulators can significantly impact NSP-Minnesota's results of operations.

Tax Reform — Regulatory Proceedings

In December 2017, the TCJA was signed into law, enacting significant changes to the Internal Revenue Code, including a reduction of the corporate income tax rate from 35% to 21% and a resulting reduction in deferred tax assets and liabilities.

As a result of IRS requirements and past regulatory treatment of income taxes in the determination of regulated rates, the impacts of TCJA are primarily recognized as a regulatory liability. Treatment of these tax benefits, (e.g., degree to which benefits will be used to refund currently effective rates and/or used to mitigate other costs and potential future rate increases) is subject to regulatory approval.

Concluded and ongoing regulatory TCJA proceedings:

Utility Service	Approval Date	Additional Information
Electric and Natural Gas	August 2018	*Minnesota* — In 2018, the MPUC ordered NSP-Minnesota to refund the 2018 impacts of TCJA, including $135 million to electric customers and low income program funding, and $6 million to natural gas customers.
Electric	July 2018	*South Dakota* — In July 2018, the SDPUC approved a settlement providing a one-time customer refund of $11 million for the 2018 impact of the TCJA, while NSP-Minnesota would retain the TCJA benefits in 2019 and 2020 in exchange for a two-year rate case moratorium.
Natural Gas	November 2018	*North Dakota* — In November 2018, the NDPSC approved a TCJA settlement in which NSP-Minnesota will amortize $1 million annually of the regulatory asset for the remediation of the MGP site in Fargo, ND and retain the TCJA savings to offset the MGP amortization expense.
Electric	February 2019	*North Dakota* — In February 2019, the NDPSC approved a settlement including a one-time customer refund of $10 million for 2018, while NSP-Minnesota would retain the TCJA benefits in 2019 and 2020 in exchange for a two-year rate case moratorium.

See Note 7 to the consolidated financial statements for further information.

Pending and Recently Concluded Regulatory Proceedings

Mechanism	Utility Service	Amount Requested (in millions)	Filing Date	Approval	Additional Information
NSP-Minnesota (MPUC)					
TCR	Electric	$98	November 2017	Pending	Reflects the revenue requirements for 2018 and a true-up for 2017 and is based on a proposed ROE of 10%. MPUC decision is expected during the first quarter of 2019.
CIP Incentive	Electric & Natural Gas	$34	March 2018	Received	MPUC approved 2017 CIP electric and natural gas financial incentives, effective October 2018, of $30 million and $4 million, respectively.
CIP Rider	Electric & Natural Gas	$57	March 2018	Received	The MPUC approved the forecasted 2018 electric and natural gas CIP riders with estimated 2019 recovery of $48 million and $9 million of electric and natural gas CIP expenses, respectively.
2018 GUIC	Natural Gas	$23	November 2017	Pending	Proposed ROE of 10%. MPUC decision is expected during the first quarter of 2019.
2019 GUIC	Natural Gas	$29	November 2018	Pending	Proposed ROE of 10.25%. Timing of MPUC decision is uncertain.
RDF	Electric	$42	October 2018	Received	MPUC approved the 2019 RDF rate based on a net revenue requirement of $42 million, effective January 2019.
RES	Electric	$23	November 2017	Pending	Reflects the revenue requirements for 2018, 2017 true-up and a proposed ROE of 10%. MPUC decision is expected in the first quarter of 2019.

See Rate Matters within Note 10 to the consolidated financial statements for further information.

Mankato Energy Center Acquisition — In November 2018, NSP-Minnesota reached an agreement with Southern Power Company to purchase the 760 MW natural gas combined cycle Mankato Energy Center for approximately $650 million. NSP-Minnesota previously contracted to purchase the energy and capacity of this facility through a PPA. The asset acquisition is anticipated to close in mid-2019 and is subject to regulatory approvals from the MPUC, NDPSC, FERC, and the DOJ. The acquisition is projected to provide net customer savings of approximately $50 million to $150 million over the life of the plant.

Wind Repowering Acquisition — In December 2018, NSP-Minnesota filed with the MPUC to acquire the Jeffers and Community Wind North wind farms from Longroad Energy. The wind farms will have approximately 70 MW of capacity after being repowered. The repowering is expected to be completed by December 2020 to qualify for the 100% PTC benefit. The acquisition is projected to provide customer savings of approximately $7 million over the life of the wind farms. The cost of the acquisition is $135 million and is pending MPUC approval.

Item 7A — Quantitative and Qualitative Disclosures About Market Risk

Derivatives, Risk Management and Market Risk

NSP-Minnesota is exposed to a variety of market risks in the normal course of business. Market risk is the potential loss that may occur as a result of adverse changes in the market or fair value of a particular instrument or commodity. All financial and commodity-related instruments, including derivatives, are subject to market risk.

See Note 8 to the consolidated financial statements for further information.

NSP-Minnesota is exposed to the impact of adverse changes in price for energy and energy related products, which is partially mitigated by the use of commodity derivatives. In addition to ongoing monitoring and maintaining credit policies intended to minimize overall credit risk, management takes steps to mitigate changes in credit and concentration risks associated with its derivatives and other contracts, including parental guarantees and requests of collateral.

While NSP-Minnesota expects that the counterparties will perform under the contracts underlying its derivatives, the contracts expose NSP-Minnesota to some credit and non-performance risk.

Distress in the financial markets may impact counterparty risk, the fair value of the securities in the nuclear decommissioning fund and pension fund and NSP-Minnesota's ability to earn a return on short-term investments.

Commodity Price Risk — NSP-Minnesota is exposed to commodity price risk in its electric and natural gas operations. Commodity price risk is managed by entering into long- and short-term physical purchase and sales contracts for electric capacity, energy and energy-related products and fuels used in generation and distribution activities.

Commodity price risk is also managed through the use of financial derivative instruments. NSP-Minnesota's risk management policy allows it to manage commodity price risk within each rate-regulated operation per commission approved hedge plans.

Wholesale and Commodity Trading Risk — NSP-Minnesota conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy. energy-related instruments and natural gas-related instruments, including derivatives. NSP-Minnesota's risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee.

At Dec. 31, 2018, fair values by source for net commodity trading contract assets were as follows:

	Futures / Forwards					
(Millions of Dollars)	Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Futures/ Forwards Fair Value
NSP-Minnesota	2	$ 2.2	$ 5.4	$ 1.7	$ 1.4	$ 10.7

	Options					
(Millions of Dollars)	Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Futures/ Forwards Fair Value
NSP-Minnesota	2	$ 0.3	$ 4.2	$ 0.8	$ —	$ 5.3

2 — Prices based on models and other valuation methods.

Changes in the fair value of commodity trading contracts before the impacts of margin-sharing for the years ended Dec. 31, were as follows:

(Millions of Dollars)	2018	2017
Fair value of commodity trading net contract assets outstanding at Jan. 1	$ 15.7	$ 9.9
Contracts realized or settled during the period	(2.0)	(3.7)
Commodity trading contract additions and changes during the period	2.3	9.5
Fair value of commodity trading net contract assets outstanding at Dec. 31	$ 16.0	$ 15.7

At Dec. 31, 2018, a 10% increase in market prices for commodity trading contracts would increase pretax income by approximately $16.6 million, whereas a 10% decrease would decrease pretax income by approximately $16.5 million. At Dec. 31, 2017, a 10% increase in market prices for commodity trading contracts would decrease pretax income by approximately $0.2 million, whereas a 10% decrease would increase pretax income by approximately $0.2 million.

NSP-Minnesota's wholesale and commodity trading operations measure the outstanding risk exposure to price changes on transactions, contracts and obligations using VaR. VaR expresses the potential change in fair value on the outstanding transactions, contracts and obligations over a particular period of time under normal market conditions.

VaRs for the NSP-Minnesota and PSCo commodity trading operations, calculated on a consolidated basis using a Monte Carlo simulation with a 95% confidence level and a one-day holding period:

(Millions of Dollars)	Year Ended Dec. 31	VaR Limit	Average	High	Low
2018	$ 4.83	$ 6.00	$ 0.62	$ 5.63	$ 0.06
2017	0.18	3.00	0.21	0.66	0.04

In November 2018, management temporarily increased the VaR limit to accommodate a 10-year transaction. NSP-Minnesota has been systematically hedging the transaction and the consolidated VaR returned below $3 million in January 2019.

Nuclear Fuel Supply — NSP-Minnesota is scheduled to take delivery of approximately 24% of its 2019 and approximately 54% of its 2020 enriched nuclear material requirements from sources that could be impacted by events in Ukraine and extended sanctions against Russia. Long-term, through 2024, NSP-Minnesota is scheduled to take delivery of approximately 32% of its average enriched nuclear material requirements from these sources. Alternate potential sources provide the flexibility to manage NSP-Minnesota's nuclear fuel supply. NSP-Minnesota periodically assesses if further actions are required to assure a secure supply of enriched nuclear material.

Disruptions in third party nuclear fuel supply contracts due to bankruptcies or change of contract assignments have not materially impacted NSP-Minnesota's operational or financial performance.

Interest Rate Risk — NSP-Minnesota is subject to interest rate risk. NSP-Minnesota's risk management policy allows interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate derivatives such as swaps, caps, collars and put or call options.

A 100-basis-point change in the benchmark rate on NSP-Minnesota's variable rate debt would impact annual pretax interest expense by approximately $1.5 million in 2018 and $1.1 million in 2017.

NSP-Minnesota maintains a nuclear decommissioning fund, as required by the NRC. The nuclear decommissioning fund is subject to interest rate risk and equity price risk. The fund is invested in a diversified portfolio of cash equivalents, debt securities, equity securities and other investments. These investments may be used only for the purpose of decommissioning NSP-Minnesota's nuclear generating plants. Realized and unrealized gains on the decommissioning fund investments are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Fluctuations in equity prices or interest rates affecting the nuclear decommissioning fund do not have a direct impact on earnings due to the application of regulatory accounting.

See Note 8 to the consolidated financial statements for further information.

Credit Risk — NSP-Minnesota is also exposed to credit risk. Credit risk relates to the risk of loss resulting from counterparties' nonperformance on their contractual obligations. NSP-Minnesota maintains credit policies intended to minimize overall credit risk and actively monitor these policies to reflect changes and scope of operations.

At Dec. 31, 2018, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $1.4 million, while a decrease in prices of 10% would have resulted in an increase in credit exposure of $12.5 million. At Dec. 31, 2017, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $6.9 million, while a decrease in prices of 10% would have resulted in an increase in credit exposure of $2.6 million.

NSP-Minnesota conducts credit reviews for all counterparties. NSP-Minnesota employ credit risk controls, such as letters of credit, parental guarantees, master netting agreements and termination provisions. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided. Distress in the financial markets could increase NSP-Minnesota's credit risk.

Fair Value Measurements

NSP-Minnesota uses derivative contracts such as futures, forwards, interest rate swaps, options and FTRs to manage commodity price and interest rate risk. Derivative contracts, with the exception of those designated as normal purchase-normal sale contracts, are reported at fair value. NSP-Minnesota's investments held in the nuclear decommissioning fund, rabbi trusts, pension and other postretirement funds are also subject to fair value accounting.

See Notes 8 and 9 to the consolidated financial statements for further information.

Commodity Derivatives — NSP-Minnesota continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions. Given the typically short duration of these contracts, the impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at Dec. 31, 2018.

Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric revenues. Credit risk adjustments for other commodity derivative instruments are recorded as other comprehensive income or deferred as regulatory assets and liabilities. Classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. The impact of discounting commodity derivative liabilities for credit risk was immaterial at Dec. 31, 2018.

Item 8 — Financial Statements and Supplementary Data

See Item 15-1 for an index of financial statements included herein.

See Note 14 to the consolidated financial statements for further information.

Management Report on Internal Controls Over Financial Reporting

The management of NSP-Minnesota is responsible for establishing and maintaining adequate internal control over financial reporting. NSP-Minnesota's internal control system was designed to provide reasonable assurance to Xcel Energy Inc.'s and NSP-Minnesota's management and board of directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

NSP-Minnesota management assessed the effectiveness of NSP-Minnesota's internal control over financial reporting as of Dec. 31, 2018. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control — Integrated Framework (2013).* Based on our assessment, we believe that, as of Dec. 31, 2018, NSP-Minnesota's internal control over financial reporting is effective at the reasonable assurance level based on those criteria.

/s/ BEN FOWKE	/s/ ROBERT C. FRENZEL
Ben Fowke	Robert C. Frenzel
Chairman and Chief Executive Officer	Executive Vice President, Chief Financial Officer
Feb. 22, 2019	Feb. 22, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of

Northern States Power Company, a Minnesota corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Northern States Power Company, a Minnesota corporation and subsidiaries (the "Company") as of December 31, 2018 and 2017, the related consolidated statements of income, comprehensive income, cash flows and, common stockholder's equity for each of the three years in the period ended December 31, 2018, and the related notes and the schedule listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 22, 2019

We have served as the Company's auditor since 2002.

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NSP-MINNESOTA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(amounts in millions)

	Year Ended Dec. 31		
	2018	2017	2016
Operating revenues			
Electric, non-affiliates	$ 4,034.3	$ 4,051.5	$ 3,929.1
Electric, affiliates	473.7	490.2	475.5
Natural gas	583.1	531.9	467.4
Other	30.8	28.4	28.3
Total operating revenues	5,121.9	5,102.0	4,900.3
Operating expenses			
Electric fuel and purchased power	1,701.1	1,626.9	1,542.6
Cost of natural gas sold and transported	345.1	301.8	252.8
Cost of sales — other	19.7	18.1	20.0
Operating and maintenance expenses	1,223.3	1,198.3	1,232.2
Conservation program expenses	118.0	120.1	97.9
Depreciation and amortization	741.6	700.6	596.7
Taxes (other than income taxes)	256.6	253.5	246.0
Total operating expenses	4,405.4	4,219.3	3,988.2
Operating income	716.5	882.7	912.1
Other expense, net	(6.5)	(9.1)	(12.6)
Allowance for funds used during construction — equity	23.8	29.5	27.7
Interest charges and financing costs			
Interest charges — includes other financing costs of $7.4, $7.3 and $7.1 respectively	226.8	228.4	226.5
Allowance for funds used during construction — debt	(12.5)	(15.1)	(12.5)
Total interest charges and financing costs	214.3	213.3	214.0
Income before income taxes	519.5	689.8	713.2
Income taxes	27.2	199.7	224.5
Net income	$ 492.3	$ 490.1	$ 488.7

See Notes to Consolidated Financial Statements

NSP-MINNESOTA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(amounts in millions)

	Year Ended Dec. 31		
	2018	2017	2016
Net income	$ 492.3	$ 490.1	$ 488.7
Other comprehensive income (loss)			
Pension and retiree medical benefits:			
Net pension and retiree medical benefits gains (losses) arising during the period, net of tax of $0.3, $(0.4) and $(0.5), respectively	0.6	(0.5)	(0.7)
Amortization of losses included in net periodic benefit cost, net of tax of $0.1, $0.1 and $0, respectively	0.2	0.1	0.1
	0.8	(0.4)	(0.6)
Derivative instruments:			
Net fair value increase, net of tax of $0, $0 and $0, respectively	—	0.1	—
Reclassification of losses to net income, net of tax of $0.3, $0.6 and $0.6, respectively	0.7	0.9	0.9
	0.7	1.0	0.9
Marketable securities:			
Net fair value decrease, net of tax of $0, $0 and $0, respectively	(0.1)	—	—
Other comprehensive income	1.4	0.6	0.3
Comprehensive income	$ 493.7	$ 490.7	$ 489.0

See Notes to Consolidated Financial Statements

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NSP-MINNESOTA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(amounts in millions)

	Year Ended Dec. 31		
	2018	2017	2016
Operating activities			
Net income	$ 492.3	$ 490.1	$ 488.7
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	748.1	707.0	602.9
Nuclear fuel amortization	121.9	114.4	117.0
Deferred income taxes	41.3	193.2	196.2
Allowance for equity funds used during construction	(23.8)	(29.5)	(27.7)
Provision for bad debts	16.2	15.7	15.0
Net realized and unrealized hedging and derivative transactions	27.0	(2.8)	3.7
Changes in operating assets and liabilities:			
Accounts receivable	(42.7)	(29.8)	(53.1)
Accrued unbilled revenues	7.4	(18.1)	(32.5)
Inventories	(21.4)	7.6	(1.1)
Other current assets	94.4	(25.3)	(17.0)
Accounts payable	10.5	46.5	24.1
Net regulatory assets and liabilities	182.3	(36.4)	46.9
Other current liabilities	(64.0)	(71.8)	19.1
Pension and other employee benefit obligations	(75.8)	(56.7)	(42.3)
Other, net	(31.5)	(31.3)	(35.0)
Net cash provided by operating activities	1,482.2	1,272.8	1,304.9
Investing activities			
Utility capital/construction expenditures	(1,149.7)	(987.2)	(1,176.8)
Purchases of investment securities	(852.9)	(1,690.5)	(506.3)
Proceeds from the sale of investment securities	832.6	1,668.9	478.9
Investments in utility money pool arrangement	(805.0)	(122.0)	(747.5)
Repayments from utility money pool arrangement	805.0	122.0	747.5
Other, net	(3.5)	(3.5)	(1.0)
Net cash used in investing activities	(1,173.5)	(1,012.3)	(1,205.2)
Financing activities			
Proceeds from (repayments of) short-term borrowings, net	130.0	(65.0)	(138.0)
Borrowings under utility money pool arrangement	479.0	838.0	424.0
Repayments under utility money pool arrangement	(564.0)	(753.0)	(424.0)
Proceeds from issuance of long-term debt	—	585.2	342.5
Repayments of long-term debt, including reacquisition premiums	—	(507.9)	—
Capital contributions from parent	108.8	145.0	96.7
Dividends paid to parent	(456.3)	(506.6)	(395.9)
Net cash used in by financing activities	(302.5)	(264.3)	(94.7)
Net change in cash and cash equivalents	6.2	(3.8)	5.0
Cash and cash equivalents at beginning of period	43.8	47.6	42.6
Cash and cash equivalents at end of period	$ 50.0	$ 43.8	$ 47.6
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	$ (207.4)	$ (214.2)	$ (201.4)
Cash received (paid) for income taxes, net	89.0	(70.9)	(39.0)
Supplemental disclosure of non-cash investing transactions:			
Accrued property, plant and equipment additions	$ 92.5	$ 93.1	$ 120.8
Inventory transfers to property, plant and equipment	60.8	17.3	35.1
Allowances for equity funds used during construction	23.8	29.5	27.7

See Notes to Consolidated Financial Statements

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NSP-MINNESOTA AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(amounts in millions, except share and per share data)

	Dec. 31 2018	Dec. 31 2017
Assets		
Current assets		
Cash and cash equivalents	$ 50.0	$ 43.8
Accounts receivable, net	380.9	345.1
Accounts receivable from affiliates	11.0	48.5
Accrued unbilled revenues	270.3	277.7
Inventories	299.4	337.7
Regulatory assets	280.3	276.4
Derivative instruments	25.8	25.2
Prepaid taxes	—	79.1
Prepayments and other	28.9	43.7
Total current assets	1,346.6	1,477.2
Property, plant and equipment	13,541.7	13,033.6
Other assets		
Nuclear decommissioning fund and other investments	2,107.2	2,192.4
Regulatory assets	1,454.1	1,190.4
Derivative instruments	17.0	28.1
Other	3.3	4.1
Total other assets	3,581.6	3,415.0
Total assets	$ 18,469.9	$ 17,925.8
Liabilities and Equity		
Current liabilities		
Short-term debt	$ 150.0	$ 20.0
Borrowings under utility money pool arrangement	—	85.0
Accounts payable	393.6	368.3
Accounts payable to affiliates	109.7	80.1
Regulatory liabilities	262.4	83.4
Taxes accrued	230.1	229.3
Accrued interest	67.2	65.9
Dividends payable to parent	82.7	98.7
Derivative instruments	16.5	17.7
Customer deposits	53.7	95.4
Other	154.8	153.0
Total current liabilities	1,520.7	1,296.8
Deferred credits and other liabilities		
Deferred income taxes	1,682.4	1,612.3
Deferred investment tax credits	21.1	22.5
Regulatory liabilities	1,984.7	1,978.5
Asset retirement obligations	2,177.9	2,083.9
Derivative instruments	112.2	102.7
Pension and employee benefit obligations	305.1	331.1
Other	155.5	89.4
Total deferred credits and other liabilities	6,438.9	6,220.4
Commitments and contingencies		
Capitalization		
Long-term debt	4,937.2	4,933.0
Common stock — 5,000,000 shares authorized of $0.01 par value; 1,000,000 shares outstanding at Dec. 31, 2018 and 2017, respectively	—	—
Additional paid in capital	3,624.2	3,580.2
Retained earnings	1,972.0	1,919.9
Accumulated other comprehensive loss	(23.1)	(24.5)
Total common stockholder's equity	5,573.1	5,475.6
Total liabilities and equity	$ 18,469.9	$ 17,925.8

See Notes to Consolidated Financial Statements

NSP-MINNESOTA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
(amounts in millions, except share data)

	Common Stock					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholder's Equity
Balance at Dec. 31, 2015	1,000,000	$ —	$ 3,323.8	$ 1,864.3	$ (21.1)	$ 5,167.0
Net income				488.7		488.7
Other comprehensive income					0.3	0.3
Dividends declared on common stock				(411.7)		(411.7)
Contribution of capital by parent			111.3			111.3
Balance at Dec. 31, 2016	1,000,000	$ —	$ 3,435.1	$ 1,941.3	$ (20.8)	$ 5,355.6
Net income				490.1		490.1
Other comprehensive income					0.6	0.6
Dividends declared on common stock				(515.8)		(515.8)
Contribution of capital by parent			145.1			145.1
Adoption of ASU No. 2018-02				4.3	(4.3)	—
Balance at Dec. 31, 2017	1,000,000	$ —	$ 3,580.2	$ 1,919.9	$ (24.5)	$ 5,475.6
Net income				492.3		492.3
Other comprehensive income					1.4	1.4
Dividends declared on common stock				(440.2)		(440.2)
Contribution of capital by parent			44.0			44.0
Balance at Dec. 31, 2018	1,000,000	$ —	$ 3,624.2	$ 1,972.0	$ (23.1)	$ 5,573.1

See Notes to Consolidated Financial Statements

Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

General — NSP-Minnesota is engaged in the regulated generation, purchase, transmission, distribution and sale of electricity and in the regulated purchase, transportation, distribution and sale of natural gas.

NSP-Minnesota's consolidated financial statements include its wholly-owned subsidiaries. In the consolidation process, all intercompany transactions and balances are eliminated. NSP-Minnesota has investments in certain plants and transmission facilities jointly owned with nonaffiliated utilities.

NSP-Minnesota's proportionate share of jointly owned facilities is recorded as property, plant and equipment on the consolidated balance sheets and NSP-Minnesota's proportionate share of the operating costs associated with these facilities is included in its consolidated statements of income. See Note 3 for further information.

NSP-Minnesota's consolidated financial statements and disclosures are presented in accordance with GAAP. All of NSP-Minnesota's underlying accounting records also conform to the FERC uniform system of accounts or to systems required by various state regulatory commissions.

NSP-Minnesota has evaluated the impact of events occurring after Dec. 31, 2018 up to the date of issuance of these consolidated financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation.

Use of Estimates — NSP-Minnesota uses estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used on items such as plant depreciable lives or potential disallowances, AROs, certain regulatory assets and liabilities, tax provisions, uncollectible amounts, environmental costs, unbilled revenues, jurisdictional fuel and energy cost allocations and actuarially determined benefit costs. Recorded estimates are revised when better information becomes available or when actual amounts can be determined. Those revisions can affect operating results.

Regulatory Accounting — NSP-Minnesota accounts for income and expense items in accordance with accounting guidance for regulated operations. Under this guidance:

- Certain costs, which would otherwise be charged to expense or other comprehensive income, are deferred as regulatory assets based on the expected ability to recover the costs in future rates; and
- Certain credits, which would otherwise be reflected as income or other comprehensive income, are deferred as regulatory liabilities based on the expectation the amounts will be returned to customers in future rates, or because the amounts were collected in rates prior to the costs being incurred.

Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with the treatment in the rate setting process.

If changes in the regulatory environment occur, NSP-Minnesota may no longer be eligible to apply this accounting treatment, and may be required to eliminate regulatory assets and liabilities from its balance sheet. Such changes could have a material effect on NSP-Minnesota's results of operations, financial condition and cash flows.

See Note 4 for further information.

Income Taxes — NSP-Minnesota accounts for income taxes using the asset and liability method, which requires deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. NSP-Minnesota defers income taxes for all temporary differences between pretax financial and taxable income, and between the book and tax bases of assets and liabilities. NSP-Minnesota uses the tax rates that are scheduled to be in effect when the temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the period that includes the enactment date.

The effects of NSP-Minnesota's tax rate changes are generally subject to a normalization method of accounting. Therefore, the revaluation of most of its net deferred taxes upon a tax rate reduction results in the establishment of a net regulatory liability which will be refundable to utility customers over the remaining life of the related assets. A tax rate increase would result in the establishment of a similar regulatory asset.

Reversal of certain temporary differences are accounted for as current income tax expense due to the effects of past regulatory practices, when deferred taxes were not required to be recorded due to the use of flow through accounting for ratemaking purposes. Tax credits are recorded when earned unless there is a requirement to defer the benefit and amortize it over the book depreciable lives of the related property. The requirement to defer and amortize tax credits only applies to federal ITCs related to public utility property. Utility rate regulation also has resulted in the recognition of regulatory assets and liabilities related to income taxes.

Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized.

NSP-Minnesota follows the applicable accounting guidance to measure and disclose uncertain tax positions that it has taken or expects to take in its income tax returns. NSP-Minnesota recognizes a tax position in its consolidated financial statements when it is more likely than not that the position will be sustained upon examination based on the technical merits of the position.

Recognition of changes in uncertain tax positions are reflected as a component of income tax.

NSP-Minnesota reports interest and penalties related to income taxes within the other income and interest charges in the consolidated statements of income.

Xcel Energy Inc. and its subsidiaries, including NSP-Minnesota, file consolidated federal income tax returns as well as consolidated or separate state income tax returns. Federal income taxes paid by Xcel Energy Inc. are allocated to its subsidiaries based on separate company computations. A similar allocation is made for state income taxes paid by Xcel Energy Inc. in connection with consolidated state filings. Xcel Energy Inc. also allocates its own income tax benefits to its direct subsidiaries.

See Note 7 for further information.

Property, Plant and Equipment and Depreciation — Property, plant and equipment is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and AFUDC. The cost of plant retired is charged to accumulated depreciation and amortization. Amounts recovered in rates for future removal costs are recorded as regulatory liabilities. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance costs are charged to expense as incurred.

Maintenance and replacement of items determined to be less than a unit of property are charged to operating expenses as incurred. Planned maintenance activities are charged to operating expense unless the cost represents the acquisition of an additional unit of property or the replacement of an existing unit of property.

Property, plant and equipment is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. A loss is recognized in the current period if it becomes probable that part of a cost of a plant under construction or recently completed plant will be disallowed for recovery from customers and a reasonable estimate of the disallowance can be made.

For investments in property, plant and equipment that are abandoned and not expected to go into service, incurred costs and related deferred tax amounts are compared to the discounted estimated future rate recovery, and a loss is recognized, if necessary.

NSP-Minnesota records depreciation expense using the straight-line method over the plant's useful life. Actuarial life studies are performed and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 3.6% for 2018, 3.6% for 2017, and 3.2% for 2016.

See Note 3 for further information.

AROs — NSP-Minnesota accounts for AROs under accounting guidance that requires a liability for the fair value of an ARO to be recognized in the period in which it is incurred if it can be reasonably estimated, with the offsetting associated asset retirement costs capitalized as a long-lived asset. The liability is generally increased over time by applying the effective interest method of accretion, and the capitalized costs are depreciated over the useful life of the long-lived asset.

Changes resulting from revisions to the timing or amount of expected asset retirement cash flows are recognized as an increase or a decrease in the ARO. NSP-Minnesota also recovers through rates certain future plant removal costs in addition to AROs. The accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

See Note 10 for further information.

Nuclear Decommissioning — Nuclear decommissioning studies that estimate NSP-Minnesota's ultimate costs of decommissioning its nuclear power plants are performed at least every three years and submitted to the state commissions for approval.

For ratemaking purposes, NSP-Minnesota recovers the total decommissioning costs related to its nuclear power plants over each facility's expected service life based on the triennial decommissioning studies filed with state commissions. The studies consider estimated future costs of decommissioning and the market value of investments in trust funds, and recommend annual funding amounts. Amounts collected in rates are deposited in the trust funds. For financial reporting purposes, NSP-Minnesota accounts for nuclear decommissioning as an ARO.

Restricted funds for the payment of future decommissioning expenditures for NSP-Minnesota's nuclear facilities are included in nuclear decommissioning fund and other assets on the consolidated balance sheets.

See Notes 8 and 10 for further information.

Benefit Plans and Other Postretirement Benefits — NSP-Minnesota maintains pension and postretirement benefit plans for eligible employees. Recognizing the cost of providing benefits and measuring the projected benefit obligation of these plans requires management to make various assumptions and estimates.

Certain unrecognized actuarial gains and losses and unrecognized prior service costs or credits are deferred as regulatory assets and liabilities, rather than recorded as other comprehensive income, based on regulatory recovery mechanisms.

See Note 9 for further information.

Environmental Costs — Environmental costs are recorded when it is probable NSP-Minnesota is liable for remediation costs and the liability can be reasonably estimated. Costs are deferred as a regulatory asset if it is probable that the costs will be recovered from customers in future rates. Otherwise, the costs are expensed. If an environmental expense is related to facilities currently in use, such as emission-control equipment, the cost is capitalized and depreciated over the life of the plant.

Estimated remediation costs are regularly adjusted as estimates are revised and remediation proceeds. If other participating potentially responsible parties exist and acknowledge their potential involvement with a site, costs are estimated and recorded only for NSP-Minnesota's expected share of the cost.

Future costs of restoring sites are treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for removal expenses. Removal costs recovered in rates before the related costs are incurred are classified as a regulatory liability.

See Note 10 for further information.

Revenue From Contracts With Customers — Performance obligations related to the sale of energy are satisfied as energy is delivered to customers. NSP-Minnesota recognizes revenue that corresponds to the price of the energy delivered to the customer. The measurement of energy sales to customers is generally based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recognized.

NSP-Minnesota does not recognize a separate financing component of its collections from customers as contract terms are short-term in nature. NSP-Minnesota presents its revenues net of any excise or sales taxes or fees.

NSP-Minnesota recognizes sales to both native load and other end use customers on a gross basis in electric revenues and cost of sales. Revenues and charges for short term wholesale sales of excess energy transacted through RTOs are also recorded on a gross basis. Other RTO revenues and charges are recorded on a net basis in cost of sales.

NSP-Minnesota has various rate-adjustment mechanisms that provide for the recovery of natural gas, electric fuel and purchased energy costs. Cost-adjustment tariffs may increase or decrease the level of revenue collected from customers and are revised periodically for differences between the total amount collected under the clauses and the costs incurred.

When applicable, fuel cost over-recoveries (the excess of fuel revenue billed to customers over fuel costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as regulatory assets.

See Note 6 for further information.

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Cash and Cash Equivalents — NSP-Minnesota considers investments in instruments with a remaining maturity of 3 months or less at the time of purchase, to be cash equivalents.

Accounts Receivable and Allowance for Bad Debts — Accounts receivable are stated at the actual billed amount net of an allowance for bad debts. NSP-Minnesota establishes an allowance for uncollectible receivables based on a policy that reflects its expected exposure to the credit risk of customers.

As of Dec. 31, 2018 and 2017, the allowance for bad debts was $23.5 million and $21.3 million, respectively.

Inventory — Inventory is recorded at average cost. As of Dec. 31, 2018, materials and supplies, fuel and natural gas inventory were $176.3 million, $88.5 million, and $34.6 million, respectively. As of Dec. 31, 2017, materials and supplies, fuel and natural gas inventory were $209.2 million, $94.5 million, and $34.0 million, respectively.

Fair Value Measurements — NSP-Minnesota presents cash equivalents, interest rate derivatives, commodity derivatives and nuclear decommissioning fund assets at estimated fair values in its consolidated financial statements. Cash equivalents are recorded at cost plus accrued interest; money market funds are measured using quoted NAVs.

For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used to establish fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price, NSP-Minnesota may use quoted prices for similar contracts or internally prepared valuation models to determine fair value.

For the pension and postretirement plan assets and nuclear decommissioning fund, published trading data and pricing models, generally using the most observable inputs available, are utilized to estimate fair value for each security.

See Notes 8 and 9 for further information.

Derivative Instruments — NSP-Minnesota uses derivative instruments in connection with its interest rate, utility commodity price, vehicle fuel price and commodity trading activities, including forward contracts, futures, swaps and options. Any derivative instruments not qualifying for the normal purchases and normal sales exception are recorded on the consolidated balance sheets at fair value as derivative instruments. Classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship.

Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. Classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms.

Gains or losses on commodity trading transactions are recorded as a component of electric operating revenues; hedging transactions for vehicle fuel costs are recorded as a component of capital projects and O&M costs; and interest rate hedging transactions are recorded as a component of interest expense.

Normal Purchases and Normal Sales — NSP-Minnesota enters into contracts for purchases and sales of commodities for use in its operations. At inception, contracts are evaluated to determine whether a derivative exists and/or whether an instrument may be exempted from derivative accounting if designated as a normal purchase or normal sale.

See Note 8 for further information.

Commodity Trading Operations — All applicable gains and losses related to commodity trading activities are shown on a net basis in electric operating revenues in the consolidated statements of income.

Commodity trading activities are not associated with energy produced from NSP-Minnesota's generation assets or energy and capacity purchased to serve native load. Commodity trading contracts are recorded at fair market value and commodity trading results include the impact of all margin-sharing mechanisms. See Note 8 for further information.

Other Utility Items

AFUDC — AFUDC represents the cost of capital used to finance utility construction activity. AFUDC is computed by applying a composite financing rate to qualified CWIP. The amount of AFUDC capitalized as a utility construction cost is credited to other nonoperating income (for equity capital) and interest charges (for debt capital). AFUDC amounts capitalized are included in NSP-Minnesota's rate base for establishing utility rates.

Alternative Revenue — Certain rate rider mechanisms (including decoupling and CIP programs) qualify as alternative revenue programs under GAAP. These mechanisms arise from costs imposed upon the utility by action of a regulator or legislative body related to an environmental, public safety or other mandate. When certain criteria are met, such as collection within 24 months, revenue is recognized equal to the revenue requirement, which may include incentives and return on rate base items.

Billing amounts are revised periodically for differences between the total amount collected and revenue earned, which may increase or decrease the level of revenue collected from customers. Alternative revenues arising from these programs are presented on a gross basis and disclosed separately from revenue from contracts with customers in the period earned.

See Note 6 for further information.

Conservation Programs — Costs incurred for CIP programs are deferred if it is probable future revenue will recover the incurred cost. Revenues recognized for incentive programs for the recovery of lost margins and/or conservation performance incentives are limited to amounts expected to be collected within 24 months from when they are earned. Regulatory assets are recognized to reflect the amount of costs or earned incentives that have not yet been collected from customers.

Emission Allowances — Emission allowances are recorded at cost plus broker commission fees. The inventory accounting model is utilized for all emission allowances and sales of these allowances are included in electric revenues.

Nuclear Refueling Outage Costs — NSP-Minnesota uses a deferral and amortization method for nuclear refueling costs. This method amortizes refueling outage costs over the period between refueling outages consistent with rate recovery.

RECs — Cost of RECs that are utilized for compliance purposes is recorded as electric fuel and purchased power expense. Sales of RECs are recorded in electric revenues on a gross basis. The cost of these RECs and amounts credited to customers under margin-sharing mechanisms are recorded in electric fuel and purchased power expense.

2. Accounting Pronouncements

Recently Issued

Leases — In 2016, the FASB issued *Leases, Topic 842 (ASU No. 2016-02)*, which requires balance sheet recognition of right-of-use assets and lease liabilities for most leases. Adoption will occur on Jan. 1, 2019 utilizing the package of transition practical expedients provided by the new standard, including carrying forward prior conclusions of whether agreements existing before the adoption date contain leases, and whether existing leases are operating or capital/finance leases.

NSP-Minnesota expects to utilize other expedients offered by the new standard and *Leases, Topic 842 (ASU No. 2018-11)*, including elections to not recognize short term leases on the consolidated balance sheet for certain classes of assets and to implement the standard on a prospective basis. NSP-Minnesota's implementation of the new guidance is substantially complete, and is expected to result in the recognition of right-of-use assets and lease liabilities in the first quarter of 2019 for operating leases for the use of real estate, equipment and certain natural gas generating facilities operated under PPAs.

The implementation is not expected to have a significant impact on NSP-Minnesota's consolidated financial statements, other than first-time recognition of these operating leases on the consolidated balance sheet.

Recently Adopted

Revenue Recognition — In 2014, the FASB issued *Revenue from Contracts with Customers, Topic 606 (ASU No. 2014-09)*, which provides a new framework for the recognition of revenue. NSP-Minnesota implemented the guidance on a modified retrospective basis on Jan. 1, 2018. Results for reporting periods beginning after Dec. 31, 2017 are presented in accordance with Topic 606, while prior period results have not been adjusted and continue to be reported in accordance with prior accounting guidance.

The implementation did not have a material impact on NSP-Minnesota's consolidated financial statements, other than increased disclosures regarding revenues related to contracts with customers.

Classification and Measurement of Financial Instruments — In 2016, the FASB issued *Recognition and Measurement of Financial Assets and Financial Liabilities, Subtopic 825-10 (ASU No. 2016-01)*, which eliminated the available-for-sale classification for marketable equity securities and also replaced the cost method of accounting for non-marketable equity securities with a model for recognizing impairments and observable price changes.

NSP-Minnesota implemented the guidance on Jan. 1, 2018 and the adoption impacts were not material.

Presentation of Net Periodic Benefit Cost — In 2017, the FASB issued *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, Topic 715 (ASU No. 2017-07)*, which establishes that only the service cost portion of pension cost may be presented as a component of operating income. In addition, only the service cost portion of pension cost is eligible for capitalization.

As a result of regulatory accounting treatment, a similar amount of pension cost, including non-service components, will be recognized consistent with historical ratemaking and the impacts of adoption are limited to changes in classification of non-service costs in the consolidated statement of income.

NSP-Minnesota implemented the new guidance on Jan. 1, 2018. As a result, $14.8 million and $13.6 million of pension costs were retrospectively reclassified from operating and maintenance expenses to other expense, net on the consolidated income statement for 2017 and 2016, respectively. NSP-Minnesota used benefit cost amounts disclosed for prior periods as the basis for retrospective application.

3. Property, Plant and Equipment

Major classes of property, plant and equipment:

(Millions of Dollars)	Dec. 31, 2018	Dec. 31, 2017
Property, plant and equipment		
Electric plant	$ 17,749.3	$ 17,024.9
Natural gas plant	1,475.5	1,370.3
Common and other property	803.1	724.1
CWIP	615.1	530.1
Total property, plant and equipment	20,643.0	19,649.4
Less accumulated depreciation	(7,454.8)	(7,018.2)
Nuclear fuel	2,770.4	2,697.4
Less accumulated amortization	(2,416.9)	(2,295.0)
	$ 13,541.7	$ 13,033.6

Joint Ownership of Generation, Transmission and Gas Facilities

Jointly owned assets as of Dec. 31, 2018:

(Millions of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Percent Owned
Electric Generation:				
Sherco Unit 3	$ 604.2	$ 415.0	$ 1.0	59%
Sherco Common Facilities	145.4	100.2	1.2	80
Other	4.8	3.4	—	59
Electric Transmission:				
CapX2020 Transmission	959.6	72.7	1.9	51
Other	10.6	2.3	—	50
Total	$ 1,724.6	$ 593.6	$ 4.1	

NSP-Minnesota's share of operating expenses and construction expenditures are included in the applicable utility accounts. Respective owners are responsible for providing their own financing.

4. Regulatory Assets and Liabilities

Regulatory assets and liabilities are created for amounts that regulators may allow to be collected, or may require to be paid back to customers in future electric and natural gas rates. NSP-Minnesota would be required to recognize the write-off of regulatory assets and liabilities in net income or other comprehensive income if changes in the utility industry no longer allow for the application of regulatory accounting guidance under GAAP.

Components of regulatory assets:

(Millions of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2018		Dec. 31, 2017	
Regulatory Assets			Current	Noncurrent	Current	Noncurrent
Pension and retiree medical obligations	9	Various	$ 28.1	$ 424.3	$ 28.5	$ 403.7
Net AROs [(a)]	1, 10	Plant lives	—	323.4	—	193.1
Excess deferred taxes - TCJA	7	Various	—	153.3	—	133.1
Recoverable deferred taxes on AFUDC recorded in plant		Plant lives	—	117.6	—	119.0
Benson biomass PPA termination and asset purchase		Ten years	9.8	85.8	—	—
Contract valuation adjustments [(b)]	1, 8	Term of related contract	14.1	76.0	14.4	89.8
Laurentian biomass PPA termination		Five years	18.1	73.3	—	—
PI extended power update		Sixteen years	3.1	55.8	3.3	58.4
Purchased power contracts costs		Term of related contract	2.8	36.6	1.8	39.3
Conservation programs [(c)]	1	One to two years	34.5	21.1	40.4	25.9
Losses on reacquired debt		Term of related debt	2.1	15.5	2.2	17.6
Environmental remediation costs	1, 10	Pending future rate cases	1.3	14.3	—	24.6
Nuclear refueling outage costs	1	One to two years	36.3	13.5	49.3	19.7
Deferred purchased natural gas and electric energy costs		One to three years	5.6	12.6	13.5	13.3
Sales true-up and revenue decoupling		One to two years	38.3	6.7	37.3	12.4
State commission adjustments		Plant lives	—	3.4	—	3.5
Renewable resources and environmental initiatives		One to two years	39.2	0.4	45.9	0.4
Gas pipeline inspection and remediation costs		Less than one year	27.4	—	22.6	4.5
Other		Various	19.6	20.5	17.2	32.1
Total regulatory assets			$ 280.3	$ 1,454.1	$ 276.4	$ 1,190.4

(a) Includes amounts recorded for future recovery of AROs, less amounts recovered through nuclear decommissioning accruals and gains from decommissioning investments.

(b) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.

(c) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.

Components of regulatory liabilities:

(Millions of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2018		Dec. 31, 2017	
Regulatory Liabilities			Current	Noncurrent	Current	Noncurrent
Deferred income tax adjustments and TCJA refunds [(a)]	7	Various	$ 153.7	$ 1,465.1	$ —	$ 1,516.1
Plant removal costs	1, 10	Plant lives	—	484.6	—	441.6
ITC deferrals [(b)]	1	Various	—	8.9	—	9.5
Deferred electric energy costs		Less than one year	22.8	—	11.3	—
DOE Settlement		Less than one year	13.0	—	12.8	—
Contract valuation adjustments [(c)]	1, 8	Less than one year	10.4	—	17.2	—
Renewable resources and environmental initiatives		Less than one year	8.8	—	19.4	—
Other		Various	53.7	26.1	22.7	11.3
Total regulatory liabilities [(d)]			$ 262.4	$ 1,984.7	$ 83.4	$ 1,978.5

(a) Includes the revaluation of recoverable/regulated plant ADIT and revaluation impact of non-plant ADIT due to the TCJA.

(b) Includes impact of lower federal tax rate due to the TCJA.

(c) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.

(d) Revenue subject for refund of $12.5 million and $15.1 million for 2018 and 2017, respectively, is included in other current liabilities.

At Dec. 31, 2018 and 2017, approximately $149 million and $142 million, respectively, of NSP-Minnesota's regulatory assets represented past expenditures not earning a return. Amounts primarily related to purchased natural gas and electric energy costs and certain expenditures associated with pension.

5. Borrowings and Other Financing Instruments

Short-Term Borrowings

Money Pool — Xcel Energy Inc. and its utility subsidiaries have established a money pool arrangement that allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc. Money pool borrowings for NSP-Minnesota were as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2018	Year Ended 2018	Year Ended 2017	Year Ended 2016
Borrowing limit	$ 250	$ 250	$ 250	$ 250
Amount outstanding at period end	—	—	85	—
Average amount outstanding	18	17	25	16
Maximum amount outstanding	76	143	142	225
Weighted average interest rate, computed on a daily basis	2.23%	1.96%	1.14%	0.69%
Weighted average interest rate at period end	N/A	N/A	1.18	N/A

Commercial Paper — NSP-Minnesota meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility.

Commercial paper outstanding for NSP-Minnesota was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2018	Year Ended Dec. 31 2018	Year Ended Dec. 31 2017	Year Ended Dec. 31 2016
Borrowing limit	$ 500	$ 500	$ 500	$ 500
Amount outstanding at period end	150	150	20	85
Average amount outstanding	62	38	62	73
Maximum amount outstanding	198	198	237	353
Weighted average interest rate, computed on a daily basis	2.53%	2.08%	1.10%	0.65%
Weighted average interest rate at end of period	2.97	2.97	1.93	0.94

Letters of Credit — NSP-Minnesota uses letters of credit, typically with terms of one-year, to provide financial guarantees for certain operating obligations. At Dec. 31, 2018 and 2017, there were $37 million and $24 million of letters of credit outstanding, respectively, under the credit facility. Amounts approximate their fair value.

Credit Facility — NSP-Minnesota must have a revolving credit facility in place at least equal to the amount of its commercial paper borrowing limit and cannot issue commercial paper in an amount exceeding available capacity under this credit facility. The line of credit provides short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

Features of NSP-Minnesota's credit facility:

Debt-to-Total Capitalization Ratio (a) 2018	Debt-to-Total Capitalization Ratio (a) 2017	Amount Facility May Be Increased (millions)	Additional Periods For Which a One-Year Extension May Be Requested (b)
48%	48%	$ 100	2

(a) The credit facility has a financial covenant requiring that the debt-to-total capitalization ratio be less than or equal to 65%.

(b) All extension requests are subject to majority bank group approval.

The credit facility has a cross-default provision that NSP-Minnesota will be in default on its borrowings under the facility if it or any of its subsidiaries whose total assets exceed 15% of NSP-Minnesota's consolidated total assets, default on indebtedness in an aggregate principal amount exceeding $75 million.

If NSP-Minnesota does not comply with the covenant, an event of default may be declared, and if not remedied, any outstanding amounts due under the facility can be declared due by the lender. As of Dec. 31, 2018, NSP-Minnesota was in compliance with all financial covenants on its debt agreements.

NSP-Minnesota had the following committed credit facilities available as of Dec. 31, 2018 (in millions):

Credit Facility (a)	Drawn (b)	Available
$ 500	$ 187	$ 313

(a) This credit facility matures in June 2021 .

(b) Includes outstanding commercial paper and letters of credit.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the credit facility. NSP-Minnesota had no direct advances on the facility outstanding at Dec. 31, 2018 and 2017.

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Long-Term Borrowings and Other Financing Instruments

Generally, all property of NSP-Minnesota is subject to the lien of its first mortgage indenture. Debt premiums, discounts and expenses are amortized over the life of the related debt. The premiums, discounts and expenses for refinanced debt are deferred and amortized over the life of the new issuance.

Long term debt obligations for NSP-Minnesota as of Dec. 31:

(Millions of Dollars)	Maturity Range	Interest Rate Range 2018	Interest Rate Range 2017	2018	2017
NSP-Minnesota					
Mortgage bonds	2020-2047	2.15% - 7.13%	2.15% - 7.13%	$ 5,000	$ 5,000
Unamortized discount				(21)	(22)
Unamortized debt issuance cost				(42)	(45)
Current maturities				—	—
Total				$ 4,937	$ 4,933

Maturities of long-term debt are as follows:

(Millions of Dollars)	
2019	$ —
2020	300
2021	—
2022	300
2023	400

During 2018, NSP-Minnesota did not complete any new financings.

2017 financings:

	Amount	Financing Instrument	Interest Rate	Maturity Date
NSP-Minnesota	600 million	First mortgage bonds	3.60%	Sept. 15, 2047

Deferred Financing Costs — Deferred financing costs of approximately $42 million and $45 million, net of amortization, are presented as a deduction from the carrying amount of long-term debt at Dec. 31, 2018 and 2017, respectively.

Dividend Restrictions — NSP-Minnesota's dividends are subject to the FERC's jurisdiction, which prohibits the payment of dividends out of capital accounts. Dividend payments are solely to be paid from retained earnings.

NSP-Minnesota's state regulatory commission imposes the most restrictive dividend limitations.

Requirements and actuals as of Dec. 31, 2018:

	Equity to Total Capitalization Ratio - Required Range		Equity to Total Capitalization Ratio - Actual
	Low	High	2018
NSP-Minnesota	47.1%	57.5%	52.3%

	Unrestricted Retained Earnings	Total Capitalization	Limit on Total Capitalization
NSP-Minnesota	$ 1.0 billion	$ 10.7 billion	$ 11.5 billion

6. Revenues

Revenue is classified by the type of goods/services rendered and market/customer type. NSP-Minnesota's operating revenues (subsequent to adoption of the revised revenue guidance) consists of the following:

	Year Ended Dec. 31, 2018			
(Millions of Dollars)	Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 1,308.4	$ 308.8	$ 27.2	$ 1,644.4
C&I	2,052.1	239.3	0.2	2,291.6
Other	36.5	—	3.4	39.9
Total retail	3,397.0	548.1	30.8	3,975.9
Wholesale	189.2	—	—	189.2
Transmission	238.1	—	—	238.1
Interchange	473.7	—	—	473.7
Other	28.3	11.7	—	40.0
Total revenue from contracts with customers	4,326.3	559.8	30.8	4,916.9
Alternative revenue and other	181.7	23.3	—	205.0
Total revenues	$ 4,508.0	$ 583.1	$ 30.8	$ 5,121.9

7. Income Taxes

Federal Tax Reform — In 2017, the TCJA was signed into law. The key provisions impacting Xcel Energy (which includes NSP-Minnesota), generally beginning in 2018, include:

- Corporate federal tax rate reduction from 35% to 21%;
- Normalization of resulting plant-related excess deferred taxes;
- Elimination of the corporate alternative minimum tax;
- Continued interest expense deductibility and discontinued bonus depreciation for regulated public utilities;
- Limitations on certain executive compensation deductions;
- Limitations on certain deductions for NOLs arising after Dec. 31, 2017 (limited to 80% of taxable income);
- Repeal of the section 199 manufacturing deduction; and,
- Reduced deductions for meals and entertainment as well as state and local lobbying.

Xcel Energy estimated the effects of the TCJA, which have been reflected in the consolidated financial statements.

Reductions in deferred tax assets and liabilities due to a decrease in corporate federal tax rates typically result in a net tax benefit. However, the impacts are primarily recognized as regulatory liabilities refundable to utility customers as a result of IRS requirements and past regulatory treatment.

Estimated impacts of the new tax law for NSP-Minnesota in December 2017 included:

- $1.1 billion ($1.5 billion grossed-up for tax) of reclassifications of plant-related excess deferred taxes to regulatory liabilities upon valuation at the new 21% federal rate. The regulatory liabilities will be amortized consistent with IRS normalization requirements, resulting in customer refunds over the average remaining life of the related property;
- $133 million and $56 million of reclassifications (grossed-up for tax) of excess deferred taxes for non-plant related deferred tax assets and liabilities, respectively, to regulatory assets and liabilities; and
- $19 million of total estimated income tax expense related to the federal tax reform implementation, and a $5 million reduction to net income related to the allocation of Xcel Energy Services Inc.'s tax rate change on its deferred taxes.

Xcel Energy accounted for the state tax impacts of federal tax reform based on enacted state tax laws. Any future state tax law changes related to the TCJA will be accounted for in the periods state laws are enacted.

Federal Tax Loss Carryback Claims — In 2012 - 2015, Xcel Energy identified certain expenses related to 2009, 2010, 2011, 2013, 2014 and 2015 that qualify for an extended carryback beyond the typical two-year carryback period. As a result of a higher tax rate in prior years, Xcel Energy recognized a tax benefit of approximately $5 million in 2015, $17 million in 2014, $12 million in 2013 and $15 million in 2012.

Federal Audit — NSP-Minnesota is a member of the Xcel Energy affiliated group that files a consolidated federal income tax return. Statute of limitations applicable to Xcel Energy's consolidated federal income tax returns expire as follows:

Tax Year(s)	Expiration
2009 - 2014	October 2019
2015	September 2019
2016	September 2020
2017	September 2021

In 2012, the IRS commenced an examination of tax years 2010 and 2011, including the 2009 carryback claim. In 2017, Xcel Energy and the Office of Appeals reached an agreement and the benefit related to the agreed upon portions was recognized. In the second quarter of 2018, the Joint Committee on Taxation completed its review and took no exception to the agreement. As a result, the remaining unrecognized tax benefit was released and recorded as a payable to the IRS.

In the third quarter of 2015, the IRS commenced an examination of tax years 2012 and 2013. In the third quarter of 2017, the IRS concluded the audit of tax years 2012 and 2013 and proposed an adjustment that would impact Xcel Energy's NOL and ETR. Xcel Energy filed a protest with the IRS. As of Dec. 31, 2018, the case has been forwarded to the Office of Appeals and Xcel Energy has recognized its best estimate of income tax expense that will result from a final resolution of this issue; however, the outcome and timing of a resolution is unknown.

In the fourth quarter of 2018, the IRS began an audit of tax years 2014 - 2016, however no adjustments have been proposed.

State Audits — NSP-Minnesota is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of Dec. 31, 2018, NSP-Minnesota's earliest open tax year subject to examination by state taxing authorities under applicable statutes of limitations is 2009. In the fourth quarter of 2018, the Minnesota audit of tax years 2010 - 2014 concluded with no material adjustments.

Unrecognized Tax Benefits — Unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the annual ETR. In addition, the unrecognized tax benefit balance includes temporary tax positions for which the ultimate deductibility is highly certain, but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the ETR but would accelerate the payment to the taxing authority to an earlier period.

Unrecognized tax benefits - permanent vs temporary:

(Millions of Dollars)	Dec. 31, 2018	Dec. 31, 2017
Unrecognized tax benefit — Permanent tax positions	$ 11.6	$ 10.2
Unrecognized tax benefit — Temporary tax positions	5.3	7.9
Total unrecognized tax benefit	$ 16.9	$ 18.1

Changes in unrecognized tax benefits:

(Millions of Dollars)	2018	2017	2016
Balance at Jan. 1	$ 18.1	$ 60.8	$ 55.4
Additions based on tax positions related to the current year	2.0	2.7	3.7
Reductions based on tax positions related to the current year	(0.3)	(1.7)	(0.2)
Additions for tax positions of prior years	0.6	5.7	3.9
Reductions for tax positions of prior years	(1.1)	(49.4)	(2.0)
Settlements with taxing authorities	(2.4)	—	—
Balance at Dec. 31	$ 16.9	$ 18.1	$ 60.8

Unrecognized tax benefits were reduced by tax benefits associated with NOL and tax credit carryforwards:

(Millions of Dollars)	Dec. 31, 2018	Dec. 31, 2017
NOL and tax credit carryforwards	$ (12.7)	$ (12.8)

Net deferred tax liability associated with the unrecognized tax benefit amounts and related NOLs and tax credits carryforwards were $7.3 million and $5.7 million at Dec. 31, 2018 and Dec. 31, 2017, respectively.

As the IRS Appeals and federal audit progress and state audits resume, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $13.7 million in the next 12 months.

Payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards.

Interest payable related to unrecognized tax benefits:

(Millions of Dollars)	2018	2017	2016
Payable for interest related to unrecognized tax benefits at Jan. 1	$ (0.9)	$ (2.0)	$ (0.2)
Interest (expense) income related to unrecognized tax benefits	(0.3)	1.1	(1.8)
Payable for interest related to unrecognized tax benefits at Dec. 31	$ (1.2)	$ (0.9)	$ (2.0)

No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2018, 2017, or 2016.

Other Income Tax Matters — NOL amounts represent the tax loss that is carried forward and tax credits represent the deferred tax asset. NOL and tax credit carryforwards as of Dec. 31 were as follows:

(Millions of Dollars)	2018	2017
Federal NOL carryforward	$ —	$ 631.6
Federal tax credit carryforwards	379.4	301.6
State NOL carryforwards	221.2	275.5
Valuation allowances for state NOL carryforwards	(0.8)	(0.9)
State tax credit carryforwards, net of federal detriment [(a)]	87.9	90.7
Valuation allowances for state credit carryforwards, net of federal benefit [(b)]	(78.5)	(82.2)

(a) State tax credit carryforwards are net of federal detriment of $23.4 million and $24.1 million as of Dec. 31, 2018 and 2017, respectively.

(b) Valuation allowances for state tax credit carryforwards were net of federal benefit of $20.9 million and $21.8 million as of Dec. 31, 2018 and 2017, respectively.

Federal carryforward periods expire between 2021 and 2038 and state carryforward periods expire between 2019 and 2035.

Total income tax expense from operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense.

Effective income tax rate for years ended Dec. 31:

	2018	2017 [(a)]	2016 [(a)]
Federal statutory rate	21.0%	35.0%	35.0%
State income tax on pretax income, net of federal tax effect	7.1	5.8	5.8
Increases (decreases) in tax from:			
Wind PTCs recognized	(13.6)	(11.4)	(8.2)
Regulatory differences - ARAM [(b)]	(9.1)	(0.1)	(0.1)
Other tax credit recognized, net of federal income tax expense	(1.3)	(1.0)	(0.8)
Regulatory differences - other utility plant items	0.3	(0.2)	(0.2)
Change in unrecognized tax benefits	0.1	(1.6)	0.2
Tax reform	—	2.7	—
Other, net	0.7	(0.2)	(0.2)
Effective income tax rate	5.2%	29.0%	31.5%

(a) Prior periods have been reclassified to conform to current year presentation.

(b) ARAM is a method to flow back excess deferred taxes to customers.

Components of income tax expense for years ended Dec. 31:

(Millions of Dollars)	2018	2017	2016
Current federal tax (benefit) expense	$ (16.8)	$ 29.6	$ 19.3
Current state tax expense	5.2	14.7	9.4
Current change in unrecognized tax (benefit) expense	(1.1)	(36.2)	1.3
Deferred federal tax (benefit) expense	(2.4)	121.6	142.3
Deferred state tax expense	42.1	46.7	53.8
Deferred change in unrecognized tax expense	1.6	24.9	0.1
Deferred ITCs	(1.4)	(1.6)	(1.7)
Total income tax expense	$ 27.2	$ 199.7	$ 224.5

Components of deferred income tax expense as of Dec. 31:

(Millions of Dollars)	2018	2017	2016
Deferred tax expense (benefit) excluding items below	$ 70.1	$ (1,176.4)	$ 225.1
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(28.2)	1,369.9	(28.7)
Tax expense allocated to other comprehensive income, net of adoption of ASU No. 2018-02, and other	(0.6)	(0.3)	(0.2)
Deferred tax expense	$ 41.3	$ 193.2	$ 196.2

Components of the net deferred tax liability as of Dec. 31:

(Millions of Dollars)	2018	2017
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 2,257.6	$ 2,253.2
Regulatory assets	263.1	222.7
Pension expense	64.7	54.2
Other	11.3	16.4
Total deferred tax liabilities	$ 2,596.7	$ 2,546.5
Deferred tax assets:		
Regulatory liabilities	$ 382.8	$ 386.6
Tax credit carryforward	467.3	392.4
NOL carryforward	17.9	153.5
NOL and tax credit valuation allowance	(78.6)	(82.2)
Other employee benefits	38.6	37.3
Deferred ITCs	6.4	6.8
Rate refund	49.7	6.6
Other	30.2	33.2
Total deferred tax assets	$ 914.3	$ 934.2
Net deferred tax liability	$ 1,682.4	$ 1,612.3

8. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

The accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance.

- Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices.
- Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, or priced with models using highly observable inputs.
- Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

Specific valuation methods include:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted NAV.

Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. The fair values for commingled funds are measured using NAVs. The investments in commingled funds may be redeemed for NAV with proper notice. Private equity commingled fund investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate commingled funds investments may be redeemed with proper notice, however, may be delayed or discounted as a result of fund illiquidity.

Investments in debt securities — Fair values for debt securities are determined by a third party pricing service using recent trades and observable spreads from benchmark interest rates for similar securities.

Interest rate derivatives — The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — The methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations, and are generally assigned a Level 2 classification. When contractual settlements relate to inactive delivery locations or extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable forecasts of forward prices and volatilities on a valuation is evaluated, and may result in Level 3 classification.

Electric commodity derivatives held by NSP-Minnesota include transmission congestion instruments, generally referred to as FTRs. FTRs purchased from a RTO are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path. The value of an FTR is derived from, and designed to offset, the cost of transmission congestion. In addition to overall transmission load, congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of an FTR.

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of important inputs to the value of FTRs between auction processes, including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3.

Non-trading monthly FTR settlements are included in fuel and purchased energy cost recovery mechanisms, and therefore changes in the fair value of the yet to be settled portions of most FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of NSP-Minnesota's FTRs relative to its electric utility operations, the numerous unobservable quantitative inputs pertinent to the value of FTRs are insignificant to the consolidated financial statements of NSP-Minnesota.

Non-Derivative Fair Value Measurements

The NRC requires NSP-Minnesota to maintain a portfolio of investments to fund the costs of decommissioning its nuclear generating plants. Assets of the nuclear decommissioning fund are legally restricted for the purpose of decommissioning these facilities. The fund contains cash equivalents, debt securities, equity securities and other investments. NSP-Minnesota uses the MPUC approved asset allocation for the escrow and investment targets by asset class for both the escrow and qualified trust.

NSP-Minnesota recognizes the costs of funding the decommissioning over the lives of the nuclear plants, assuming rate recovery of all costs. Realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund are deferred as a component of the regulatory asset.

Unrealized gains for the nuclear decommissioning fund were $450.1 million and $559.9 million as of Dec. 31, 2018 and 2017, respectively, and unrealized losses were $44.8 million and $7.4 million as of Dec. 31, 2018 and 2017, respectively.

Non-derivative instruments with recurring fair value measurements in the nuclear decommissioning fund:

	Dec. 31, 2018					
		Fair Value				
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	NAV	Total
Nuclear decommissioning fund (a)						
Cash equivalents	$ 24.3	$ 24.3	$ —	$ —	$ —	$ 24.3
Commingled funds	758.1	79.2	—	—	819.1	$ 898.3
Debt securities	465.6	—	435.6	—	—	$ 435.6
Equity securities	401.4	696.5	—	—	—	$ 696.5
Total	$ 1,649.4	$ 800.0	$ 435.6	$ —	$ 819.1	$ 2,054.7

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $52.5 million of rabbi trust assets and miscellaneous investments.

	Dec. 31, 2017					
		Fair Value				
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	NAV	Total
Nuclear decommissioning fund (a)						
Cash equivalents	$ 28.7	$ 28.7	$ —	$ —	$ —	$ 28.7
Commingled funds	701.3	222.8	—	—	659.1	$ 881.9
Debt securities	437.7	—	441.6	—	—	$ 441.6
Equity securities	423.1	791.1	—	—	—	$ 791.1
Total	$ 1,590.8	$1,042.6	$ 441.6	$ —	$ 659.1	$ 2,143.3

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $49.1 million of rabbi trust assets and miscellaneous investments.

For the years ended Dec. 31, 2018 and 2017, there were no Level 3 nuclear decommissioning fund investments or transfer of amounts between levels.

Contractual maturity dates of debt securities in the nuclear decommissioning fund as of Dec. 31, 2018:

	Final Contractual Maturity				
(Millions of Dollars)	Due in 1 Year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years	Total
Debt securities	$ 10.6	$ 106.9	$ 210.5	$ 107.6	$ 435.6

Rabbi Trusts

NSP-Minnesota has established a rabbi trust to provide partial funding for future deferred compensation plan distributions.

Cost and fair value of assets held in rabbi trusts:

	Dec. 31, 2018				
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$ 0.4	$ 0.4	$ —	$ —	$ 0.4
Mutual funds	10.8	10.7	—	—	10.7
Total	$ 11.2	$ 11.1	$ —	$ —	$ 11.1

	Dec. 31, 2017				
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$ 0.8	$ 0.8	$ —	$ —	$ 0.8
Mutual funds	10.3	11.3	—	—	$ 11.3
Total	$ 11.1	$ 12.1	$ —	$ —	$ 12.1

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet.

Derivative Fair Value Measurements

NSP-Minnesota enters into derivative instruments, including forward contracts, futures, swaps and options, for trading purposes and to manage risk in connection with changes in interest rates, utility commodity prices and vehicle fuel prices.

Interest Rate Derivatives — NSP-Minnesota enters into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes.

As of Dec. 31, 2018, accumulated other comprehensive losses related to interest rate derivatives included $0.8 million of net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings.

Wholesale and Commodity Trading Risk — NSP-Minnesota conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy, energy-related instruments and natural gas-related instruments, including derivatives. NSP-Minnesota is allowed to conduct these activities within guidelines and limitations as approved by its risk management committee, comprised of management personnel not directly involved in activities governed by this policy.

Commodity Derivatives — NSP-Minnesota enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric and natural gas operations, as well as for trading purposes. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, natural gas for resale, FTRs, vehicle fuel, and weather derivatives.

As of Dec. 31, 2018, NSP-Minnesota had no vehicle fuel contracts designated as cash flow hedges. NSP-Minnesota may enter into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers, but may not be designated as qualifying hedging transactions. Changes in the fair value of non-trading commodity derivative instruments are recorded in other comprehensive income or deferred as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Immaterial amounts to income related to the ineffectiveness of cash flow hedges were recorded for the years ended Dec. 31, 2018 and 2017.

As of Dec. 31, 2018, there were no net gains related to commodity derivative cash flow hedges recorded as a component of accumulated other comprehensive losses or related amounts expected to be reclassified into earnings during the next 12 months.

NSP-Minnesota enters into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving its electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in electric operating revenues, net of amounts credited to customers under margin-sharing mechanisms.

Gross notional amounts of commodity forwards, options and FTRs at Dec. 31:

(Amounts in Millions) [(a) (b)]	2018	2017
MWh of electricity	56.8	41.7
MMBtu of natural gas	42.7	23.8
Gallons of vehicle fuel	—	0.2

(a) Amounts are not reflective of net positions in the underlying commodities.

(b) Notional amounts for options are included on a gross basis, but are weighted for the probability of exercise.

Consideration of Credit Risk and Concentrations — NSP-Minnesota continuously monitors the creditworthiness of counterparties to its interest rate derivatives and commodity derivative contracts prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented in the consolidated balance sheets.

NSP-Minnesota employs additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees, standardized master netting agreements and termination provisions that allow for offsetting of positive and negative exposures. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided.

NSP-Minnesota's most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to its wholesale, trading and non-trading commodity activities. As of Dec. 31, 2018, six of NSP-Minnesota's 10 most significant counterparties for these activities, comprising $35.9 million or 44% of this credit exposure, had investment grade credit ratings from Standard & Poor's, Moody's or Fitch Ratings.

Two of the 10 most significant counterparties, comprising $14.4 million or 18% of this credit exposure, were not rated by these external agencies, but based on NSP-Minnesota's internal analysis, had credit quality consistent with investment grade. One of the 10 most significant counterparties, comprising $1.3 million or 2% of this credit exposure, had credit quality less than investment grade, based on ratings from external analysis. One of the 10 most significant counterparties, comprising $11.8 million or 14% of this credit exposure, had credit quality less than investment grade based on rating from internal analysis. Seven of these significant counterparties are municipal or cooperative electric entities, or other utilities.

Qualifying Cash Flow Hedges — Financial impact of qualifying interest rate and vehicle fuel cash flow hedges on NSP-Minnesota's accumulated other comprehensive loss, included in the consolidated statements of common stockholder's equity and in the consolidated statements of comprehensive income:

(Millions of Dollars)	2018	2017	2016
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$ (20.9)	$ (18.2)	$ (19.1)
After-tax net unrealized gains related to derivatives accounted for as hedges	—	0.1	—
After-tax net realized losses on derivative transactions reclassified into earnings	0.7	0.9	0.9
Adoption of ASU. 2018-02 [(a)]	—	(3.7)	—
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	$ (20.2)	$ (20.9)	$ (18.2)

(a) In 2017, NSP-Minnesota implemented ASU No. 2018-02 related to TCJA, which resulted in reclassification of certain credit balances within net accumulated other comprehensive loss to retained earnings.

Impact of derivative activity:

(Millions of Dollars)	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in: Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities
Year Ended Dec. 31, 2018		
Other derivative instruments		
Electric commodity	$ —	$ (5.5)
Natural gas commodity	—	1.8
Total	$ —	$ (3.7)
Year Ended Dec. 31, 2017		
Derivatives designated as cash flow hedges		
Vehicle fuel and other commodity	$ 0.1	$ —
Total	$ 0.1	$ —
Other derivative instruments		
Electric commodity	$ —	$ 9.3
Natural gas commodity	—	(1.9)
Total	$ —	$ 7.4
Year Ended Dec. 31, 2016		
Other derivative instruments		
Electric commodity	—	14.4
Natural gas commodity	—	(1.2)
Total	$ —	$ 13.2

(Millions of Dollars)	Pre-Tax (Gains) Losses Reclassified into Income During the Period from: Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Year Ended Dec. 31, 2018			
Derivatives designated as cash flow hedges			
Interest rate	$ 1.1 (a)	$ —	$ —
Vehicle fuel and other commodity	(0.1) (b)	—	—
Total	$ 1.0	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ 10.9 (c)
Electric commodity	—	3.3 (d)	—
Natural gas commodity	—	(1.9) (e)	(1.3) (e)
Total	$ —	$ 1.4	$ 9.6
Year Ended Dec. 31, 2017			
Derivatives designated as cash flow hedges			
Interest rate	$ 1.5 (a)	$ —	$ —
Total	$ 1.5	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ 9.4 (c)
Electric commodity	—	(13.8) (d)	—
Natural gas commodity	—	1.0 (e)	(1.2) (e)
Total	$ —	$ (12.8)	$ 8.2
Year Ended Dec. 31, 2016			
Derivatives designated as cash flow hedges			
Interest rate	$ 1.4 (a)	$ —	$ —
Vehicle fuel and other commodity	0.1 (b)	—	—
Total	$ 1.5	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ 2.8 (c)
Electric commodity	—	(6.1) (d)	—
Natural gas commodity	—	4.0 (e)	(2.2) (e)
Total	$ —	$ (2.1)	$ 0.6

(a) Amounts are recorded to interest charges.

(b) Amounts are recorded to O&M expenses.

(c) Amounts are recorded to electric operating revenues. Portions of these gains and losses are subject to sharing with electric customers through margin-sharing mechanisms and deducted from gross revenue, as appropriate.

(d) Amounts are recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

(e) Amounts are recorded to cost of natural gas sold and transported. These derivative settlement gains and losses are shared with natural gas customers through purchased natural gas cost-recovery mechanisms, and reclassified out of income as regulatory assets and liabilities, as appropriate.

NSP-Minnesota had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2018, 2017 and 2016.

Credit Related Contingent Features — Contract provisions for derivative instruments that NSP-Minnesota enters into, including those accounted for as normal purchase-normal sale contracts and therefore not reflected on the consolidated balance sheets, may require the posting of collateral or settlement of the contracts for various reasons, including if NSP-Minnesota's credit ratings are downgraded below its investment grade credit rating by any of the major credit rating agencies, or for cross-default contractual provisions if there was a failure under other financing arrangements related to payment terms or other covenants. As of Dec. 31, 2018 and 2017, there were no derivative instruments in a liability position with such underlying contract provisions.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that NSP-Minnesota's ability to fulfill its contractual obligations is reasonably expected to be impaired. NSP-Minnesota had no collateral posted related to adequate assurance clauses in derivative contracts as of Dec. 31, 2018 and 2017.

Recurring Fair Value Measurements — The following table presents for each of the fair value hierarchy levels, NSP-Minnesota's derivative assets and liabilities measured at fair value on a recurring basis at Dec. 31, 2018 and 2017:

	Dec. 31, 2018						Dec. 31, 2017					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting [(a)]	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting [(a)]	Total
Current derivative assets												
Derivatives designated as cash flow hedges:												
Vehicle fuel and other commodity	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 0.1	$ —	$ 0.1	$ —	$ 0.1
Other derivative instruments:												
Commodity trading	1.1	27.1	2.2	30.4	(16.0)	14.4	1.7	17.1	0.1	18.9	(11.7)	7.2
Electric commodity	—	—	10.5	10.5	(0.1)	10.4	—	—	17.6	17.6	(0.4)	17.2
Natural gas commodity	—	1.0	—	1.0	—	1.0	—	0.1	—	0.1	—	0.1
Total current derivative assets	$ 1.1	$ 28.1	$ 12.7	$ 41.9	$ (16.1)	25.8	$ 1.7	$ 17.3	$ 17.7	$ 36.7	$ (12.1)	24.6
PPAs [(b)]						—						0.6
Current derivative instruments						$ 25.8						$ 25.2
Noncurrent derivative assets												
Other derivative instruments:												
Commodity trading	$ —	$ 25.3	$ 5.0	$ 30.3	$ (13.4)	$ 16.9	$ —	$ 29.1	$ 5.4	$ 34.5	$ (6.5)	$ 28.0
Total noncurrent derivative assets	$ —	$ 25.3	$ 5.0	$ 30.3	$ (13.4)	16.9	$ —	$ 29.1	$ 5.4	$ 34.5	$ (6.5)	28.0
PPAs [(b)]						0.1						0.1
Noncurrent derivative instruments						$ 17.0						$ 28.1

	Dec. 31, 2018						Dec. 31, 2017					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting [(a)]	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting [(a)]	Total
Current derivative liabilities												
Other derivative instruments:												
Commodity trading	$ 1.4	$ 23.9	$ 1.7	$ 27.0	$ (24.5)	$ 2.5	$ 1.7	$ 13.9	$ —	$ 15.6	$ (12.0)	$ 3.6
Electric commodity	—	—	0.1	0.1	(0.1)	—	—	—	0.4	0.4	(0.4)	—
Total current derivative liabilities	$ 1.4	$ 23.9	$ 1.8	$ 27.1	$ (24.6)	2.5	$ 1.7	$ 13.9	$ 0.4	$ 16.0	$ (12.4)	3.6
PPAs [(b)]						14.0						14.1
Current derivative instruments						$ 16.5						$ 17.7
Noncurrent derivative liabilities												
Other derivative instruments:												
Commodity trading	$ 0.1	$ 16.0	$ 1.6	$ 17.7	$ 17.9	$ 35.6	$ —	$ 22.2	$ —	$ 22.2	$ (9.4)	$ 12.8
Total noncurrent derivative liabilities	$ 0.1	$ 16.0	$ 1.6	$ 17.7	$ 17.9	35.6	$ —	$ 22.2	$ —	$ 22.2	$ (9.4)	12.8
PPAs [(b)]						76.6						89.9
Noncurrent derivative instruments						$ 112.2						$ 102.7

[(a)] NSP-Minnesota nets derivative instruments and related collateral in its consolidated balance sheet when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Dec. 31, 2018 and 2017. At Dec. 31, 2018 and 2017, derivative assets and liabilities include $31.5 million and $0 million of obligations to return cash collateral, respectively. At Dec. 31, 2018 and 2017, derivative assets and liabilities include the rights to reclaim cash collateral of $8.7 million and $3.1 million, respectively. The counterparty netting excludes settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

[(b)] During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

Changes in Level 3 commodity derivatives for the years ended Dec. 31, 2018, 2017 and 2016:

	Year Ended Dec. 31		
(Millions of Dollars)	2018	2017	2016
Balance at Jan. 1	$ 22.6	$ 15.3	$ 13.0
Purchases	26.4	40.6	28.0
Settlements	(17.2)	(41.7)	(47.2)
Net transactions recorded during the period:			
(Losses) gains recognized in earnings [(a)]	(1.5)	5.5	—
Net (losses) gains recognized as regulatory assets and liabilities	(16.0)	2.9	21.5
Balance at Dec. 31	$ 14.3	$ 22.6	$ 15.3

(a) Amounts relate to commodity derivatives held at the end of the period.

NSP-Minnesota recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for the years ended 2016 - 2018.

Fair Value of Long-Term Debt

As of Dec. 31, other financial instruments for which the carrying amount did not equal fair value:

	2018		2017	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$ 4,937.2	$ 5,230.9	$ 4,933.0	$ 5,601.9

Fair value of NSP-Minnesota's long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. Fair value estimates are based on information available to management as of Dec. 31, 2018 and 2017, and given the observability of the inputs, fair values presented for long-term debt were assigned as Level 2.

9. Benefit Plans and Other Postretirement Benefits

Xcel Energy, which includes NSP-Minnesota, has several noncontributory, defined benefit pension plans that cover almost all employees. Generally, benefits are based on a combination of years of service and average pay. Xcel Energy's and NSP-Minnesota's policy is to fully fund into an external trust the actuarially determined pension costs subject to the limitations of applicable employee benefit and tax laws.

In addition to the qualified pension plans, Xcel Energy maintains a SERP and a nonqualified pension plan. The SERP is maintained for certain executives that were participants in the plan in 2008, when the SERP was closed to new participants. The nonqualified pension plan provides benefits for compensation that is in excess of the limits applicable to the qualified pension plans, with distributions funded by Xcel Energy's consolidated operating cash flows. Obligations of the SERP and nonqualified plan as of Dec. 31, 2018 and 2017 were $33 million and $37 million, respectively, of which $4 million and $5 million were attributable to NSP-Minnesota. In 2018 and 2017, Xcel Energy recognized net benefit cost for the SERP and nonqualified plans of $4 million and $5 million, respectively, of which $1 million was attributable to NSP-Minnesota in both years.

In 2016, Xcel Energy established rabbi trusts to provide partial funding for future distributions of the SERP and its deferred compensation plan. Rabbi trust funding of deferred compensation plan distributions attributable to NSP-Minnesota will be supplemented by NSP-Minnesota's consolidated operating cash flows.

Xcel Energy has a contributory health and welfare benefit plan that provides health care and death benefits to certain Xcel Energy retirees.

- NSP-Minnesota discontinued subsidizing health care benefits for non-bargaining employees retiring after 1998 and for bargaining employees who retired after 1999.

Xcel Energy and NSP-Minnesota base the investment-return assumption on expected long-term performance for each of the asset classes in its pension and postretirement health care portfolios.

For pension assets, Xcel Energy and NSP-Minnesota consider the historical returns achieved by their asset portfolio over the past 20 years or longer period, as well as the long-term projected return levels. Xcel Energy and NSP-Minnesota continually review their pension assumptions.

Pension cost determination assumes a forecasted mix of investment types over the long-term.

- Investment returns in 2018 were below the assumed level of 7.10%;
- Investment returns in 2017 were above the assumed level of 7.10%;
- Investment returns in 2016 were below the assumed level of 7.10%; and
- In 2019, NSP-Minnesota's expected investment-return assumption is 7.10%.

Pension plan and postretirement benefit assets are invested in a portfolio according to Xcel Energy's and NSP-Minnesota's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the asset allocation given the long-term risk, return, correlation and liquidity characteristics of each particular asset class.

There were no significant concentrations of risk in any industry, index, or entity. Market volatility can impact even well-diversified portfolios and significantly affect the return levels achieved by the assets in any year.

State agencies also have issued guidelines to the funding of postretirement benefit costs.

Xcel Energy's ongoing investment strategy is based on plan-specific investment recommendations that seek to minimize potential investment and interest rate risk as a plan's funded status increases over time. The investment recommendations result in a greater percentage of long-duration fixed income securities being allocated to specific plans having relatively higher funded status ratios and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios.

Plan Assets

The following presents, for each of the fair value hierarchy levels, NSP-Minnesota's pension plan assets measured at fair value:

	Dec. 31, 2018 [a]					Dec. 31, 2017 [a]				
(Millions of Dollars)	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 31.8	$ —	$ —	$ —	$ 31.8	$ 53.4	$ —	$ —	$ —	$ 53.4
Commingled funds:	241.0	—	—	271.2	512.2	285.2	—	—	302.4	587.6
Debt securities:	—	143.7	—	—	143.7	—	159.0	—	—	159.0
Equity securities:	29.3	—	—	—	29.3	32.1	—	—	—	32.1
Other	0.5	1.3	—	(8.2)	(6.4)	(8.7)	1.0	—	0.1	$ (7.6)
Total	$ 302.6	$ 145.0	$ —	$ 263.0	$ 710.6	$ 362.0	$ 160.0	$ —	$ 302.5	$ 824.5

(a) See Note 8 for further information on fair value measurement inputs and methods.

The following presents, for each of the fair value hierarchy levels, NSP-Minnesota's postretirement benefit plan assets that were measured at fair value:

	Dec. 31, 2018 [a]					Dec. 31, 2017 [a]				
(Millions of Dollars)	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 0.1	$ —	$ —	$ —	$ 0.1	$ 0.4	$ —	$ —	$ —	$ 0.4
Insurance contracts	—	0.3	—	—	0.3	—	0.7	—	—	0.7
Commingled funds	0.8	—	—	0.2	1.0	2.1	—	—	—	2.1
Debt securities	—	1.0	—	—	1.0	—	2.8	—	—	2.8
Equity securities	—	—	—	—	—	0.5	—	—	—	0.5
Total	$ 0.9	$ 1.3	$ —	$ 0.2	$ 2.4	$ 3.0	$ 3.5	$ —	$ —	$ 6.5

(a) See Note 8 for further information on fair value measurement inputs and methods.

No assets transferred in or out of Level 3 for 2018 or 2017.

Funded Status — Comparisons of the actuarially computed benefit obligation, changes in plan assets and funded status of the pension and postretirement health care plans for NSP-Minnesota are as follows:

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	2018	2017	2018	2017
Change in Benefit Obligation:				
Obligation at Jan. 1	$ 1,035.1	$ 1,036.5	$ 88.8	$ 86.7
Service cost	28.0	27.8	0.2	0.1
Interest cost	35.2	40.7	3.1	3.4
Plan amendments	—	(4.4)	—	—
Actuarial (gain) loss	(50.8)	64.1	(9.0)	5.9
Plan participants' contributions	—	—	0.4	0.4
Benefit payments [a]	(140.5)	(129.6)	(7.5)	(7.7)
Obligation at Dec. 31	$ 907.0	$ 1,035.1	$ 76.0	$ 88.8
Change in Fair Value of Plan Assets:				
Fair value of plan assets at Jan. 1	$ 824.5	$ 783.2	$ 6.5	$ 3.7
Actual return on plan assets	(36.5)	110.1	—	—
Employer contributions	63.1	60.7	3.0	10.1
Plan participants' contributions	—	—	0.4	0.4
Benefit payments	(140.5)	(129.5)	(7.5)	(7.7)
Fair value of plan assets at Dec. 31	$ 710.6	$ 824.5	$ 2.4	$ 6.5
Funded status of plans at Dec. 31	$ (196.4)	$ (210.6)	$ (73.6)	$ (82.3)
Amounts recognized in the Consolidated Balance Sheet at Dec. 31:				
Current assets (liabilities)	$ —	$ —	$ (4.8)	$ (1.3)
Noncurrent assets (liabilities)	(196.4)	(210.6)	(68.8)	(81.0)
Net amounts recognized	$ (196.4)	$ (210.6)	$ (73.6)	$ (82.3)

(a) Includes approximately $105 million of lump-sum benefit payments used in the determination of a settlement charge.

Significant Assumptions Used to Measure Benefit Obligations:				
Discount rate for year-end valuation	4.31%	3.63%	4.32%	3.62%
Expected average long-term increase in compensation level	3.75%	3.75%	N/A	N/A
Mortality table	RP-2014	RP-2014	RP-2014	RP-2014
Health care costs trend rate — initial: Pre-65	N/A	N/A	6.50%	7.00%
Health care costs trend rate — initial: Post-65	N/A	N/A	5.30%	5.50%
Ultimate trend assumption — initial: Pre-65	N/A	N/A	4.50%	4.50%
Ultimate trend assumption — initial: Post-65	N/A	N/A	4.50%	4.50%
Years until ultimate trend is reached	N/A	N/A	4	5

The accumulated benefit obligation for the pension plan was $845 million and $969 million as of Dec. 31, 2018 and 2017, respectively.

Net Periodic Benefit Cost (Credit) — Net periodic benefit cost (credit) other than the service cost component is included in other income in the consolidated statement of income.

Components of net periodic benefit cost (credit) and the amounts recognized in other comprehensive income and regulatory assets and liabilities are as follows:

	Pension Benefits			Postretirement Benefits		
(Millions of Dollars)	2018	2017	2016	2018	2017	2016
Service cost	$ 28.0	$ 27.8	$ 28.3	$ 0.2	$ 0.1	$ 0.1
Interest cost	35.2	40.7	45.4	3.1	3.4	3.9
Expected return on plan assets	(58.2)	(60.1)	(60.9)	(0.4)	(0.2)	(0.2)
Amortization of prior service cost	(0.1)	1.1	0.9	(3.0)	(3.0)	(3.0)
Amortization of net loss	38.5	39.6	36.8	2.4	2.0	1.6
Settlement charge [(a)]	48.8	48.2	—	—	—	—
Net periodic pension cost	92.2	97.3	50.5	2.3	2.3	2.4
Costs not recognized due to effects of regulation	(66.0)	(72.2)	(20.9)	—	—	—
Net benefit cost recognized for financial reporting	$ 26.2	$ 25.1	$ 29.6	$ 2.3	$ 2.3	$ 2.4
Significant Assumptions Used to Measure Costs:						
Discount rate	3.63%	4.13%	4.66%	3.62%	4.13%	4.65%
Expected average long-term increase in compensation level	3.75	3.75	4.00	—	—	—
Expected average long-term rate of return on assets	7.10	7.10	7.10	5.30	5.80	5.80

(a) A settlement charge is required when the amount of lump-sum distributions during the year is greater than the sum of the service and interest cost components of the annual net periodic pension cost. In 2018 and 2017, as a result of lump-sum distributions during the 2018 and 2017 plan years, NSP-Minnesota recorded a total pension settlement charge of $48.8 million in 2018 and $48.2 million in 2017, which was not recognized due to the effects of regulation.

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	2018	2017	2018	2017
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:				
Net loss	$ 502.0	$ 545.3	$ 34.3	$ 45.3
Prior service (credit) cost	(1.2)	(1.3)	(12.4)	(15.4)
Total	$ 500.8	$ 544.0	$ 21.9	$ 29.9
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:				
Current regulatory assets	$ 35.5	$ 37.7	$ —	$ —
Noncurrent regulatory assets	465.3	506.3	20.5	28.0
Deferred income taxes	—	—	0.4	0.5
Net-of-tax accumulated other comprehensive income	—	—	1.0	1.4
Total	$ 500.8	$ 544.0	$ 21.9	$ 29.9
Measurement date	Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017

Cash Flows — Cash funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the funding requirements of income tax and other pension-related regulations. Required contributions were made in 2016 - 2019 to meet minimum funding requirements. Total voluntary and required pension funding contributions across all four of Xcel Energy's pension plans were as follows:

- $150 million in January 2019, of which $47 million is attributable to NSP-Minnesota;
- $150 million in 2018, of which $63 million was attributable to NSP-Minnesota;
- $162 million in 2017, of which $61 million was attributable to NSP-Minnesota; and,
- $125 million in 2016, of which $49 million was attributable to NSP-Minnesota.

The postretirement health care plans have no funding requirements other than fulfilling benefit payment obligations, when claims are presented and approved. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities. Voluntary postretirement funding contributions:

- $11 million in January 2019, of which $7 million is attributable to NSP-Minnesota;
- $11 million in 2018, of which $3 million, was attributable to NSP-Minnesota;
- $20 million in 2017, of which $10 million was attributable to NSP-Minnesota; and,
- $18 million in 2016, of which $9 million was attributable to NSP-Minnesota.

Target asset allocations:

	Pension Benefits		Postretirement Benefits	
	2018	2017	2018	2017
Domestic and international equity securities	37%	38%	18%	24%
Long-duration fixed income and interest rate swap securities	28	23	—	—
Short-to-intermediate fixed income securities	18	21	70	60
Alternative investments	15	16	8	9
Cash	2	2	4	7
Total	100%	100%	100%	100%

Plan Amendments — Xcel Energy, which includes NSP-Minnesota, amended the Xcel Energy Pension Plan in 2017 to reduce supplemental benefits for non-bargaining participants as well as to allow the transfer of a portion of non-qualified pension obligations into the qualified plans. In 2016, the Xcel Energy Pension Plan was amended to change the discount rate basis for lump-sum conversion to annuity participants and annuity conversion to lump-sum participants.

In 2018 and 2017, there were no plan amendments made which affected the benefit obligation.

Projected Benefit Payments

NSP-Minnesota's projected benefit payments:

(Millions of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
2019	$ 93.4	$ 7.2	$ —	$ 7.2
2020	81.2	7.0	—	7.0
2021	80.1	6.7	—	6.7
2022	79.0	6.3	—	6.3
2023	77.2	6.0	—	6.0
2024-2027	342.3	26.0	—	26.0

Defined Contribution Plans

Xcel Energy, which includes NSP-Minnesota, maintains 401(k) and other defined contribution plans that cover most employees. The expense to these plans for NSP-Minnesota was approximately $12 million in 2018, $12 million in 2017 and $12 million in 2016.

Multiemployer Plans

NSP-Minnesota contributes to several union multiemployer pension and other postretirement benefit plans, none of which are individually significant. These plans provide pension and postretirement health care benefits to certain union employees who may perform services for multiple employers and do not participate in the NSP-Minnesota sponsored pension and postretirement health care plans. Contributing to these types of plans creates risk that differs from providing benefits under NSP-Minnesota sponsored plans, in that if another participating employer ceases to contribute to a multiemployer plan, additional unfunded obligations may need to be funded over time by remaining participating employers.

10. Commitments and Contingencies

Legal

NSP-Minnesota is involved in various litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves complex judgments about future events. Management maintains accruals for losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on NSP-Minnesota's financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Rate Matters

Sherco — In NSP-Minnesota's 2013 fuel reconciliation filing, the MPUC made recovery of replacement power costs associated with the 2011 incident at its Sherco Unit 3 plant provisional and subject to further review following conclusion of litigation commenced by NSP-Minnesota, SMMPA (Co-owner of Sherco Unit 3) and insurance companies against GE.

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In 2018, NSP-Minnesota and SMMPA reached a settlement with GE. NSP-Minnesota has notified the MPUC of its proposal to refund the GE settlement proceeds back to customers through the FCA. The insurance providers continued their litigation against GE and the case went to trial. In 2018, GE prevailed in the lawsuit with the insurance companies, however, the jury found comparable fault, finding that GE was 52% and NSP-Minnesota was 48% at fault. At that point in the litigation, NSP-Minnesota was no longer involved in the case and was not present to make arguments about its role in the event. The specific issue leading to the fault apportionment was also not before the jury and not relevant to the outcome of the trial.

In January 2019, the DOC recommended that NSP-Minnesota refund $20 million of previously recovered purchased power costs to its customers, based on the jury's apportionment of fault. The OAG recommended the MPUC withhold any decision until the underlying litigation by the insurance providers (currently under appeal) is concluded. The DOC subsequently filed comments agreeing with the OAG's recommendation to withhold a decision pending the outcome of any appeals. NSP-Minnesota filed reply comments arguing that the DOC recommendations are without merit and that it acted prudently in operating the plant and its settlement with GE was reasonable.

MISO ROE Complaints — In November 2013 and February 2015, customers filed complaints against MISO TOs including NSP-Minnesota and NSP-Wisconsin. The first complaint argued for a reduction in the base ROE in MISO transmission formula rates from 12.38% to 9.15%, and removal of ROE adders (including those for RTO membership). The second complaint sought to reduce base ROE from 12.38% to 8.67%. In September 2016, the FERC issued an order granting a 10.32% base ROE (10.82% with the RTO adder) effective for the first complaint period of Nov. 12, 2013 to Feb. 11, 2015 and subsequent to the date of the order. The D.C. Circuit subsequently vacated and remanded FERC Opinion No. 531, which had established the ROE methodology on which the September 2016 FERC order was based.

In October 2018, the FERC issued a New England Transmission Owners base ROE order that addressed the D.C. Circuit's actions on Opinion No. 531. Under a new proposed two step ROE approach, the FERC has indicated an intention to dismiss an ROE complaint if the existing ROE falls within the range of just and reasonable ROEs based on equal weighting of the DCF, CAPM, and Expected Earnings models. The FERC proposes that if necessary, it would then set a new ROE by averaging the results of these models plus a Risk Premium model.

With respect to the MISO TOs, the FERC subsequently made preliminary determinations in a November 2018 order that the MISO base ROE in effect for the first complaint period (12.38%) was outside the range of reasonableness, and should be reduced. The FERC indicated its preliminary analysis using the new ROE approach resulted in a base ROE of 10.28% for the first compliant period, compared to the previously ordered base ROE of 10.32%. A procedural schedule has been set for the first half of 2019, with the FERC expected to act no earlier than the second half of 2019. NSP-Minnesota has recognized a current refund liability consistent with its best estimate of the final ROE.

Environmental

New and changing federal and state environmental mandates can create financial liabilities for NSP-Minnesota, which are normally recovered through the regulated rate process.

Site Remediation — Various federal and state environmental laws impose liability where hazardous substances or other regulated materials have been released to the environment. NSP-Minnesota may sometimes pay all or a portion of the cost to remediate sites where past activities of NSP-Minnesota's predecessors or other parties have caused environmental contamination.

Environmental contingencies could arise from various situations, including sites of former MGPs; and third-party sites, such as landfills, for which NSP-Minnesota is alleged to have sent wastes to that site.

MGP, Landfill or Disposal Sites — NSP-Minnesota is currently investigating or remediating six MGP, landfill or other disposal sites sites across its service territories, and these activities will continue through at least 2019. NSP-Minnesota accrued $6 million as of Dec. 31, 2018, and $19 million as of Dec. 31, 2017 for these sites. There may be insurance recovery and/or recovery from other potentially responsible parties, offsetting some portion of costs incurred.

Environmental Requirements — Water and Waste

Coal Ash Regulation — NSP-Minnesota's operations are subject to federal and state laws that impose requirements for handling, storage, treatment and disposal of solid waste. In 2015, the EPA published the CCR Rule. Litigation was brought challenging the rule in the D.C. Circuit. Under the CCR Rule, utilities are required to complete groundwater sampling around their CCR landfills and surface impoundments. By the end of 2019, only three of NSP-Minnesota's regulated ash units are expected to be in operation. NSP-Minnesota is conducting additional groundwater sampling and will evaluate whether corrective action is required at any CCR landfills or surface impoundments.

Until NSP-Minnesota completes its assessment, it is uncertain what impact, if any, there will be on the operations, financial condition or cash flows. In August 2018, the D.C. Circuit ruled that the EPA cannot allow utilities to continue to use unlined impoundments (including clay lined impoundments) for the storage or disposal of coal ash. Litigation is ongoing regarding the deadline for closing or retrofitting these impoundments. The decision will require NSP-Minnesota to expedite closure plans for one impoundment in Minnesota (see ARO removal costs below) and will require the construction of a new impoundment, which is estimated to cost $6 million.

Federal CWA WOTUS Rule — In 2015, the EPA and Corps published a final rule that significantly broadened the scope of waters under the CWA that are subject to federal jurisdiction, referred to as "WOTUS". The Rule has been subject to significant litigation and is currently stayed in a portion of the country. NSP-Minnesota cannot estimate potential impacts until the legal and administrative processes are finalized, but expects costs will be recoverable through regulatory mechanisms.

Federal CWA ELG — In 2015, the EPA issued a final ELG rule for power plants that discharge treated effluent to surface waters as well as utility-owned landfills that receive CCRs. In 2017, the EPA delayed the compliance date for flue gas desulfurization wastewater and bottom ash transport until November 2020. After 2020, NSP-Minnesota estimates that ELG compliance will cost approximately $10 million to complete. The EPA, however, is conducting a rulemaking process to potentially revise the effluent limitations and pretreatment standards, which may impact compliance costs. NSP-Minnesota anticipates these costs will be fully recoverable through regulatory mechanisms.

Federal CWA Section 316(b) — The federal CWA requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available for minimizing impingement and entrainment of aquatic species. NSP-Minnesota estimates the likely cost for complying with impingement and entrainment requirements is approximately $39 million, to be incurred between 2019 and 2028. NSP-Minnesota believes six plants could be required by state regulators to make improvements to reduce impingement and entrainment. The exact total cost of the impingement and entrainment improvements is uncertain, but could be up to $194 million. NSP-Minnesota anticipates these costs will be fully recoverable through regulatory mechanisms.

AROs — AROs have been recorded for NSP-Minnesota's assets. For nuclear assets, the ARO is associated with the decommissioning of the NSP-Minnesota nuclear generating plants, Monticello and PI.

Aggregate fair value of NSP-Minnesota's legally restricted assets, for funding future nuclear decommissioning, was 2.1 billion for 2018 and 2017.

NSP-Minnesota's AROs were as follows:

	Dec. 31, 2018				
(Millions of Dollars)	Jan. 1, 2018	Amounts Settled (a)	Accretion	Cash Flow Revisions (b)	Dec. 31, 2018 (c)
Electric					
Nuclear	$ 1,873.6	$ —	$ 94.7	$ —	$ 1,968.3
Wind	94.1	—	4.3	6.5	104.9
Steam and other production	64.0	(6.6)	2.1	(10.3)	49.2
Distribution	5.8	—	0.2	8.5	14.5
Miscellaneous	1.9	—	—	(0.1)	1.8
Natural gas					
Transmission and distribution	43.6	—	1.8	(7.2)	38.2
Miscellaneous	0.2	—	—	—	0.2
Common					
Miscellaneous	0.7	—	0.1	—	0.8
Total liability	$ 2,083.9	$ (6.6)	$ 103.2	$ (2.6)	$ 2,177.9

(a) Amounts settled related to asbestos abatement projects and closure of certain ash containment facilities.

(b) In 2018, AROs were revised for changes in timing and estimates of cash flows. Changes in gas transmission and distribution AROs were mainly related to increased gas line mileage and number of services, which were more than offset by increased discount rates. Changes in electric distribution AROs primarily related to increased labor costs.

(c) There were no ARO amounts incurred in 2018.

	Dec. 31, 2017				
(Millions of Dollars)	Jan. 1, 2017	Amounts Settled (a)	Accretion	Cash Flow Revisions (b)	Dec. 31, 2017 (c)
Electric					
Nuclear	$ 2,249.3	$ —	$ 113.8	$ (489.5)	$ 1,873.6
Wind	90.1	—	4.0	—	94.1
Steam and other production	68.5	(4.9)	2.4	(2.0)	64.0
Distribution	5.6	—	0.2	—	5.8
Miscellaneous	1.8	—	0.1	—	1.9
Natural gas					
Transmission and distribution	35.8	—	1.5	6.3	43.6
Miscellaneous	0.2	—	—	—	0.2
Common					
Miscellaneous	1.3	(0.6)	—	—	0.7
Total liability	$ 2,452.6	$ (5.5)	$ 122.0	$ (485.2)	$ 2,083.9

(a) Amounts settled related to asbestos abatement projects and closure of certain ash containment facilities.

(b) In 2017, AROs were revised for changes in timing and estimates of cash flows. Nuclear AROs decreased due to updated assumptions in the nuclear triennial filing.

(c) There were no ARO amounts incurred in 2017.

Indeterminate AROs — Outside of the recorded asbestos AROs, other plants or buildings may contain asbestos due to the age of many of NSP-Minnesota's facilities, but no confirmation or measurement of the cost of removal could be determined as of Dec. 31, 2018. Therefore, an ARO has not been recorded for these facilities.

Removal Costs — NSP-Minnesota records a regulatory liability for the plant removal costs that are recovered currently in rates. These removal costs have accumulated based on varying rates as authorized by the appropriate regulatory entities. NSP-Minnesota has estimated the amount of removal costs accumulated through historic depreciation expense based on current factors used in the existing depreciation rates. Removal costs as of Dec. 31, 2018 and 2017 were $485 million and $442 million.

Nuclear Related

Nuclear Insurance — NSP-Minnesota's public liability for claims from any nuclear incident is limited to $14.1 billion under the Price-Anderson amendment to the Atomic Energy Act. NSP-Minnesota has secured $450.0 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $13.6 billion of exposure is funded by the Secondary Financial Protection Program, available from assessments by the federal government in case of a nuclear incident. NSP-Minnesota is subject to assessments of up to $137.6 million per reactor-incident for each of its three licensed reactors, for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is $20.5 million per reactor-incident during any one year. These maximum assessment amounts are both subject to inflation adjustment by the NRC and state premium taxes. The NRC's last adjustment was effective November 2018.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from NEIL and EMANI. The coverage limits are $2.3 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage, including the cost of replacement power during prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term. All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL and EMANI to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage. NSP-Minnesota could be subject to annual maximum assessments of approximately $18.0 million for business interruption insurance and $39.0 million for property damage insurance if losses exceed accumulated reserve funds.

Nuclear Fuel Disposal — NSP-Minnesota is responsible for temporarily storing spent nuclear fuel from its nuclear plants. The DOE is responsible for permanently storing spent fuel from U.S. nuclear plants, but no such facility is yet available.

NSP-Minnesota owns temporary on-site storage facilities for spent fuel at its Monticello and PI nuclear plants, which consist of storage pools and dry cask facilities. The Monticello dry-cask storage facility currently stores all 30 of the authorized canisters. The PI dry-cask storage facility currently stores 44 of the 64 authorized casks. Monticello's future spent fuel will continue to be placed in its spent fuel pool. The decommissioning plan addresses the disposition of spent fuel at the end of the licensed life.

Regulatory Plant Decommissioning Recovery — Decommissioning activities for NSP-Minnesota's nuclear facilities are planned to begin at the end of each unit's operating license and be completed by 2091. NSP-Minnesota's current operating licenses allow continued use of its Monticello nuclear plant until 2030 and its PI nuclear plant until 2033 for Unit 1 and 2034 for Unit 2.

Future decommissioning costs of nuclear facilities are estimated through triennial periodic studies that assess the costs and timing of planned nuclear decommissioning activities for each unit.

The obligation for decommissioning is expected to be funded 100% by the external decommissioning trust fund. This cost study assumes the external decommissioning fund will earn an after-tax return between 5.23% and 6.30%. Realized and unrealized gains on fund investments are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Decommissioning costs are quantified in 2014 dollars. Escalation rates are 4.36% for plant removal activities and 3.36% for fuel management and site restoration activities.

NSP-Minnesota has accumulated $2.1 billion of assets held in external decommissioning trusts in 2018. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation. Xcel Energy believes future decommissioning costs will continue to be recovered in customer rates. The following amounts were prepared on a regulatory basis and not directly recorded in the financial statements (ARO).

	Regulatory Basis	
(Millions of Dollars)	2018	2017
Estimated decommissioning cost obligation from most recently approved study (in 2014 dollars)	$ 3,012.3	$ 3,012.3
Effect of escalating costs	538.9	395.7
Estimated decommissioning cost obligation (in current dollars)	3,551.2	3,408.0
Effect of escalating costs to payment date	7,654.3	7,797.5
Estimated future decommissioning costs (undiscounted)	11,205.5	11,205.5
Effect of discounting obligation (using average risk-free interest rate of 3.33% and 2.80% for 2018 and 2017, respectively)	(6,911.5)	(6,398.1)
Discounted decommissioning cost obligation	$ 4,294.0	$ 4,807.4
Assets held in external decommissioning trust	$ 2,054.7	$ 2,143.3
Underfunding of external decommissioning fund compared to the discounted decommissioning obligation	2,239.3	2,664.1

Calculations and data used by the regulator in approving NSP-Minnesota's rates are useful in assessing future cash flows. Regulatory basis information is a means to reconcile amounts previously provided to the MPUC and utilized for regulatory purposes to amounts used for financial reporting.

Reconciliation of the discounted decommissioning cost obligation - regulated basis to the ARO recorded in accordance with GAAP:

(Millions of Dollars)	2018	2017
Discounted decommissioning cost obligation - regulated basis	$ 4,294.0	$ 4,807.4
Differences in discount rate and market risk premium	(1,446.4)	(1,402.8)
O&M costs not included for GAAP	(879.3)	(1,041.5)
ARO differences between 2017 and 2014 cost studies	—	(489.5)
Nuclear production decommissioning ARO - GAAP	$ 1,968.3	$ 1,873.6

Decommissioning expenses recognized as a result of regulation:

(Millions of Dollars)	2018	2017	2016
Annual decommissioning recorded as depreciation expense: (a) (b)	$ 20.4	$ 20.4	$ 20.4

(a) Decommissioning expense does not include depreciation of the capitalized nuclear asset retirement costs.

(b) Decommissioning expenses in 2018, 2017 and 2016 include Minnesota's retail jurisdiction annual funding requirement of approximately $14.0 million.

The 2014 nuclear decommissioning filing approved in 2015 has been used for the regulatory presentation for 2018, 2017 and 2016. The most recent triennial filing was submitted in December 2017 and was approved by the MPUC. It became effective on Jan. 1, 2019 and continued the accrual previously approved in the MPUC order, dated October 2015 from the 2014 filing. The 2020 accrual will be set subsequent to a compliance filing that is expected to be submitted in July 2019.

Leases — NSP-Minnesota leases a variety of equipment and facilities. These leases, primarily for office space, railcars, generating facilities, natural gas pipeline transportation, vehicles, aircraft and power-operated equipment, are accounted for as operating leases.

Total expenses (including capacity payments) under operating lease obligations for NSP-Minnesota and the corresponding capacity payments for PPAs accounted for as operating leases for the year ended Dec. 31:

(Millions of Dollars)	2018	2017	2016
Total expense	$ 76.2	$ 76.9	$ 79.1
Capacity payments	62.5	62.7	63.4

Included in the future commitments under operating leases are estimated future capacity payments under PPAs that have been accounted for as operating leases.

Future commitments under operating leases:

(Millions of Dollars)	Operating Leases	PPA (a) (b) Operating Leases	Total Operating Leases
2019	$ 13.5	$ 65.0	$ 78.5
2020	8.4	66.1	74.5
2021	8.4	67.1	75.5
2022	8.1	68.2	76.3
2023	7.3	69.3	76.6
Thereafter	36.0	143.5	179.5

(a) Amounts do not include PPAs accounted for as executory contracts.

(b) PPA operating leases contractually expire through 2026.

Non-Lease PPAs — NSP-Minnesota has entered into PPAs with other utilities and energy suppliers with expiration dates through 2039 for purchased power to meet system load and energy requirements, meet operating reserve obligations and as part of wholesale and commodity trading activities. In general, these agreements provide for energy payments, based on actual energy delivered and capacity payments. Certain PPAs accounted for as executory contracts also contain minimum energy purchase commitments.

Capacity and energy payments are contingent on the IPPs meeting contract obligations, including plant availability requirements. Certain contractual payments are adjusted based on market indices. The effects of price adjustments on our financial results are mitigated through purchased energy cost recovery mechanisms.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts were payments for capacity of $52.7 million, $84.1 million and $89.8 million in 2018, 2017 and 2016, respectively.

At Dec. 31, 2018, the estimated future payments for capacity and energy that NSP-Minnesota is obligated to purchase pursuant to these executory contracts, subject to availability, were as follows:

(Millions of Dollars)	Capacity	Energy (a)
2019	$ 54.0	$ 98.7
2020	54.6	109.4
2021	62.2	157.4
2022	61.3	172.9
2023	62.7	176.9
Thereafter	109.5	328.1
Total (b)	$ 404.3	$ 1,043.4

(a) Excludes contingent energy payments for renewable energy PPAs.

(b) Includes amounts allocated to NSP-Wisconsin through intercompany charges.

Fuel Contracts — NSP-Minnesota has entered into various long-term commitments for the purchase and delivery of a significant portion of its coal, nuclear fuel and natural gas requirements. These contracts expire in various years between 2019 and 2037. NSP-Minnesota is required to pay additional amounts depending on actual quantities shipped under these agreements.

Estimated minimum purchases for these contracts as of Dec. 31, 2018:

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas supply	Natural gas storage and transportation
2019	$ 194.7	$ 127.1	$ 43.6	$ 107.4
2020	87.4	50.9	1.4	97.5
2021	52.0	99.0	1.4	95.6
2022	34.7	78.5	0.8	92.6
2023	35.1	99.4	—	82.8
Thereafter	3.5	337.1	—	320.7
Total [(a)]	$ 407.4	$ 792.0	$ 47.2	$ 796.6

(a) Includes amounts allocated to NSP-Wisconsin through intercompany charges.

VIEs — Under certain PPAs, NSP-Minnesota purchases power from IPPs for which NSP-Minnesota is required to reimburse fuel costs, or to participate in tolling arrangements under which NSP-Minnesota procures the natural gas required to produce the energy that it purchases. NSP-Minnesota has determined that certain IPPs are VIEs. NSP-Minnesota is not subject to risk of loss from the operations of these entities, and no significant financial support is required other than contractual payments for energy and capacity.

NSP-Minnesota evaluated each of these VIEs for possible consolidation, including review of qualitative factors such as the length and terms of the contract, control over O&M, control over dispatch of electricity, historical and estimated future fuel and electricity prices, and financing activities.

NSP-Minnesota concluded that these entities are not required to be consolidated in its consolidated financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance. NSP-Minnesota had approximately 1002 MW and 1,069 MW of capacity under long-term PPAs at Dec. 31, 2018 and 2017, respectively, with entities that have been determined to be VIEs. These agreements have expiration dates through 2027.

Other

Guarantees — Under NSP-Minnesota's railcar lease agreement, accounted for as an operating lease, NSP-Minnesota guarantees the lessor proceeds from sale of the leased assets at the end of the lease term will at least equal the guaranteed residual value. The guarantee issued by NSP-Minnesota limits its exposure to a maximum amount stated in the guarantee; however, NSP-Minnesota expects sale proceeds to exceed the guaranteed amount.

The following table presents the guarantee issued and outstanding for NSP-Minnesota:

(Millions of Dollars)	Guarantor	Guarantee Amount	Current Exposure	Triggering Event
Guarantee of residual value of assets under the Bank of Tokyo-Mitsubishi Capital Corporation Equipment Leasing Agreement	NSP-Minnesota	$ 4.8	$ —	(a)

(a) Actual fair value of leased assets is less than the guaranteed residual value amount at the end of the lease term in 2019.

11. Other Comprehensive Income

Changes in accumulated other comprehensive loss, net of tax, for the years ended Dec. 31, 2018 and 2017:

	2018			
(Millions of Dollars)	Gains and Losses on Cash Flow Hedges	Unrealized Gains and Losses on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive (loss) income at Jan. 1	$ (20.9)	$ 0.1	$ (3.7)	$ (24.5)
Other comprehensive (loss) income before reclassifications (net of taxes of $0, $0, and $0.3 respectively)	—	(0.1)	0.6	0.5
Losses reclassified from net accumulated other comprehensive loss:				
Interest rate derivatives (net of taxes of $0.3, $0, and $0, respectively) [(a)]	0.7 [(a)]	—	—	0.7
Amortization of net actuarial loss (net of taxes of $0, $0, and $0.1, respectively)	—	—	0.2 [(b)]	0.2
Net current period other comprehensive income (loss)	0.7	(0.1)	0.8	1.4
Accumulated other comprehensive loss at Dec. 31	$ (20.2)	$ —	$ (2.9)	$ (23.1)

	2017			
(Millions of Dollars)	Gains and Losses on Cash Flow Hedges	Unrealized Gains and Losses on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive (loss) income at Jan. 1	$ (18.2)	$ 0.1	$ (2.7)	$ (20.8)
Other comprehensive (loss) income before reclassifications (net of taxes of $0, $0, and $0.1, respectively)	0.1	—	(0.5)	(0.4)
Losses reclassified from net accumulated other comprehensive loss:				
Interest rate derivatives (net of taxes of $0.6, $0, and $0, respectively)	0.9 [(a)]	—	—	0.9
Amortization of net actuarial loss (net of taxes of $0, $0, and $0.1, respectively)	—	—	0.1 [(b)]	0.1
Net current period other comprehensive income (loss)	1.0	—	(0.4)	0.6
Adoption of ASU No. 2018-02 [(c)]	(3.7)	—	(0.6)	(4.3)
Accumulated other comprehensive (loss) income at Dec. 31	$ (20.9)	$ 0.1	$ (3.7)	$ (24.5)

(a) Included in interest charges.

(b) Included in the computation of net periodic pension and postretirement benefit costs. See Note 9 for further information.

(c) In 2017, NSP-Minnesota implemented ASU No. 2018-02 related to the TCJA, which resulted in reclassification of certain credit balances within net accumulated other comprehensive loss to retained earnings.

12. Segments and Related Information

Operating results from regulated electric utility and regulated natural gas utility are each separately and regularly reviewed by NSP-Minnesota's chief operating decision maker. NSP-Minnesota evaluates performance based on profit or loss generated from the product or service provided. These segments are managed separately because the revenue streams are dependent upon regulated rate recovery, which is separately determined for each segment.

NSP-Minnesota has the following reportable segments:

- *Regulated Electric* — The regulated electric utility segment generates electricity which is transmitted and distributed in Minnesota, North Dakota and South Dakota. In addition, this segment includes sales for resale and provides wholesale transmission service to various entities in the United States. The regulated electric utility segment also includes NSP-Minnesota's wholesale commodity and trading operations.
- *Regulated Natural Gas* — The regulated natural gas utility segment transports, stores and distributes natural gas in portions of Minnesota and North Dakota.
- *All Other* — Operating segments with revenues below the necessary quantitative thresholds are included in this category. Those primarily include appliance repair services, non-utility real estate activities and revenues associated with processing solid waste into refuse-derived fuel.

Asset and capital expenditure information is not provided for NSP-Minnesota's reportable segments because as an integrated electric and natural gas utility, NSP-Minnesota operates significant assets that are not dedicated to a specific business segment, and reporting assets and capital expenditures by business segment would require arbitrary and potentially misleading allocations which may not necessarily reflect the assets that would be required for the operation of the business segments on a stand-alone basis.

To report income from operations for regulated electric and regulated natural gas utility segments, the majority of costs are directly assigned to each segment. However, some costs, such as common depreciation, common O&M expenses and interest expense are allocated based on cost causation allocators. A general allocator is used for certain general and administrative expenses, including office supplies, rent, property insurance and general advertising.

NSP-Minnesota's segment information is as follows:

(Millions of Dollars)	2018	2017	2016
Regulated Electric			
Operating revenues [(a)]	$ 4,508.0	$ 4,541.8	$ 4,404.6
Intersegment revenues	0.8	0.6	0.6
Total operating revenue	$ 4,508.8	$ 4,542.4	$ 4,405.2
Depreciation and amortization	697.8	661.3	554.3
Interest charges and financing costs	199.5	199.8	200.8
Income tax expense	16.4	179.9	215.5
Net income	450.4	462.5	465.4
Regulated Natural Gas			
Operating revenues [(a)]	$ 583.1	$ 531.9	$ 467.4
Intersegment revenues	0.5	0.5	0.5
Total operating revenue	$ 583.6	$ 532.4	$ 467.9
Depreciation and amortization	43.3	38.7	41.8
Interest charges and financing costs	14.8	13.5	13.2
Income tax expense	10.2	10.0	12.0
Net income	34.2	28.4	18.3
All Other			
Operating revenues [(a)]	$ 30.8	$ 28.3	$ 28.3
Depreciation and amortization	0.5	0.6	0.6
Interest charges and financing costs	—	—	—
Income tax expense	0.6	9.8	(3.0)
Net income	7.7	(0.8)	5.0
Consolidated Total			
Total operating revenue	$ 5,123.2	$ 5,103.1	$ 4,901.4
Reconciling eliminations	(1.3)	(1.1)	(1.1)
Consolidated total revenue	$ 5,121.9	$ 5,102.0	$ 4,900.3
Depreciation and amortization	741.6	700.6	596.7
Interest charges and financing costs	214.3	213.3	214.0
Income tax expense	27.2	199.7	224.5
Net income	492.3	490.1	488.7

(a) Operating revenues include $473.7 million, $490.2 million, and $475.5 million of intercompany revenue for the years ended Dec. 31, 2018, 2017 and 2016, respectively. See Note 13 for further information.

13. Related Party Transactions

Xcel Energy Services Inc. provides management, administrative and other services for the subsidiaries of Xcel Energy Inc., including NSP-Minnesota. The services are provided and billed to each subsidiary in accordance with service agreements executed by each subsidiary. NSP-Minnesota uses the services provided by Xcel Energy Services Inc. whenever possible. Costs are charged directly to the subsidiary and are allocated if they cannot be directly assigned.

Xcel Energy Inc., NSP-Minnesota, PSCo and SPS have established a utility money pool arrangement. See Note 5 for further information.

The electric production and transmission costs of the entire NSP System are shared by NSP-Minnesota and NSP-Wisconsin. The Interchange Agreement provides for the sharing of all costs of generation and transmission facilities of the system, including capital costs.

Significant affiliate transactions among the companies and related parties including billings under the Interchange Agreement for the years ended Dec. 31:

(Millions of Dollars)	2018	2017	2016
Operating revenues:			
Electric	$ 473.7	$ 490.2	$ 475.5
Operating expenses:			
Purchased power	61.1	66.8	63.0
Transmission expense	96.8	110.5	107.5
Other operating expenses — paid to Xcel Energy Services Inc.	534.8	539.4	513.0
Interest expense	0.3	—	—

Accounts receivable and payable with affiliates at Dec. 31 were:

	2018		2017	
(Millions of Dollars)	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Wisconsin	$ 11.0	$ —	$ 17.8	$ —
PSCo	—	17.9	—	7.7
SPS	—	4.7	—	1.0
Other subsidiaries of Xcel Energy Inc.	—	87.1	30.7	71.4
	$ 11.0	$ 109.7	$ 48.5	$ 80.1

14. Summarized Quarterly Financial Data (Unaudited)

	Quarter Ended			
(Millions of Dollars)	March 31, 2018	June 30, 2018	Sept. 30, 2018	Dec. 31, 2018
Operating revenues	$ 1,310.8	$ 1,187.7	$ 1,351.8	$ 1,271.6
Operating income	171.4	150.1	259.5	135.5
Net income	111.7	92.4	201.2	87.0

	Quarter Ended			
(Millions of Dollars)	March 31, 2017	June 30, 2017	Sept. 30, 2017	Dec. 31, 2017
Operating revenues	$ 1,307.1	$ 1,164.9	$ 1,355.8	$ 1,274.2
Operating income [(a)]	182.5	173.1	339.7	187.4
Net income	94.2	87.7	229.0	79.3

[(a)] In 2018, NSP-Minnesota implemented ASU No. 2017-07 related to net periodic benefit cost, which resulted in retrospective reclassification of pension costs from O&M expense to other income.

Item 9 — Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A — Controls and Procedures

Disclosure Controls and Procedures

NSP-Minnesota maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer and chief financial officer, allowing timely decisions regarding required disclosure.

As of Dec. 31, 2018, based on an evaluation carried out under the supervision and with the participation of NSP-Minnesota's management, including the chief executive officer and chief financial officer, of the effectiveness of its disclosure controls and the procedures, the chief executive officer and chief financial officer have concluded that NSP-Minnesota's disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

No change in NSP-Minnesota's internal control over financial reporting has occurred during the most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, NSP-Minnesota's internal control over financial reporting. NSP-Minnesota maintains internal control over financial reporting to provide reasonable assurance regarding the reliability of the financial reporting. NSP-Minnesota has evaluated and documented its controls in process activities, general computer activities, and on an entity-wide level. During the year and in preparation for issuing its report for the year ended Dec. 31, 2018 on internal controls under section 404 of the Sarbanes-Oxley Act of 2002, NSP-Minnesota conducted testing and monitoring of its internal control over financial reporting. Based on the control evaluation, testing and remediation performed, NSP-Minnesota did not identify any material control weaknesses, as defined under the standards and rules issued by the Public Company Accounting Oversight Board and as approved by the SEC and as indicated in Management Report on Internal Controls herein.

This annual report does not include an attestation report of NSP-Minnesota's independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by NSP-Minnesota's independent registered public accounting firm pursuant to the rules of the SEC that permit NSP-Minnesota to provide only management's report in this annual report.

Item 9B — Other Information

None.

PART III

Items 10, 11, 12 and 13 of Part III of Form 10-K have been omitted from this report for NSP-Minnesota in accordance with conditions set forth in general instructions I(1)(a) and (b) of Form 10-K for wholly-owned subsidiaries.

Item 10 — Directors, Executive Officers and Corporate Governance

Item 11 — Executive Compensation

Item 12 — Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Item 13 — Certain Relationships and Related Transactions, and Director Independence

Information required under this Item is contained in Xcel Energy Inc.'s Proxy Statement for its 2019 Annual Meeting of Shareholders, which is incorporated by reference.

Item 14 — Principal Accountant Fees and Services

The information required by Item 14 of Form 10-K is set forth under the heading "Independent Registered Public Accounting Firm - Audit and Non-Audit Fees" in Xcel Energy Inc.'s definitive Proxy Statement for the 2019 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about April 1, 2019. Such information set forth under such heading is incorporated herein by this reference hereto.

PART IV

Item 15 — Exhibits, Financial Statement Schedules

1	Consolidated Financial Statements:
	Management Report on Internal Controls Over Financial Reporting — For the year ended Dec. 31, 2018.
	Report of Independent Registered Public Accounting Firm — Financial Statements
	Consolidated Statements of Income — For the three years ended Dec. 31, 2018, 2017 and 2016.
	Consolidated Statements of Comprehensive Income — For the three years ended Dec. 31, 2018, 2017 and 2016.
	Consolidated Statements of Cash Flows — For the three years ended Dec. 31, 2018, 2017 and 2016.
	Consolidated Balance Sheets — As of Dec. 31, 2018 and 2017.
	Consolidated Statements of Common Stockholder's Equity — For the three years ended Dec. 31, 2018, 2017 and 2016.
2	Schedule II — Valuation and Qualifying Accounts and Reserves for the years ended Dec. 31, 2018, 2017 and 2016.
3	Exhibits
*	Indicates incorporation by reference
+	Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
3.01*	Articles of Incorporation and Amendments of Northern Power Corp. (renamed Northern States Power Co. (a Minnesota corporation) on Aug. 21, 2000)	NSP-Minnesota Form 10-12G dated Oct. 5, 2000	000-31709	3.01
3.02	By-Laws of NSP-Minnesota as Amended and Restated on Jan. 25, 2019			
4.01*	Supplemental and Restated Trust Indenture, dated May 1, 1988, from NSP-Minnesota to Harris Trust and Savings Bank, as Trustee, providing for the issuance of First Mortgage Bonds, Supplemental Indentures between NSP-Minnesota and said Trustee	Xcel Energy Inc. Form S-3 dated April 18, 2018	001-03034	4(b)(3)
4.02*	Supplemental Trust Indenture dated June 1, 1995, creating $250 million principal amount of 7.125% First Mortgage Bonds, Series due July 1, 2025	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2017	001-03034	4.11
4.03*	Supplemental Trust Indenture dated March 1, 1998, creating $150 million principal amount of 6.5% First Mortgage Bonds, Series due March 1, 2028	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2017	001-03034	4.12
4.04*	Supplemental Trust Indenture dated Aug. 1, 2000 (Assignment and Assumption of Trust Indenture)	NSP-Minnesota Form 10-12G dated Oct. 5, 2000	000-31709	4.51
4.05*	Indenture, dated July 1, 1999, between NSP-Minnesota and Norwest Bank Minnesota, NA, as Trustee, providing for the issuance of Sr. Debt Securities	Xcel Energy Inc. Form S-3 dated April 18, 2018	001-03034	4(b)(7)
4.06*	Supplemental Indenture, dated Aug. 18, 2000, supplemental to the Indenture dated July 1, 1999, among Xcel Energy, NSP-Minnesota and Wells Fargo Bank Minnesota, NA, as Trustee (Assignment and Assumption of Indenture)	NSP-Minnesota Form 10-12G dated Oct. 5, 2000	000-31709	4.63
4.07*	Supplemental Trust Indenture dated July 1, 2005 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $250 million principal amount of 5.25% First Mortgage Bonds, Series due July 15, 2035	NSP-Minnesota Form 8-K dated July 14, 2005	001-31387	4.01
4.08*	Supplemental Trust Indenture dated May 1, 2006 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $400 million principal amount of 6.25% First Mortgage Bonds, Series due June 1, 2036	NSP-Minnesota Form 8-K dated May 18, 2006	001-31387	4.01
4.09*	Supplemental Trust Indenture, dated June 1, 2007, between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee	NSP-Minnesota Form 8-K dated June 19, 2007	001-31387	4.01
4.10*	Supplemental Trust Indenture dated as of Nov. 1, 2009 between NSP-Minnesota and The Bank of New York Mellon Trust Co., NA, as successor Trustee, creating $300 million principal amount of 5.35% First Mortgage Bonds, Series due Nov. 1, 2039	NSP-Minnesota Form 8-K dated Nov. 16, 2009	001-31387	4.01
4.11*	Supplemental Trust Indenture dated as of Aug. 1, 2010 between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA, as successor Trustee, creating $250 million principal amount of 1.950% First Mortgage Bonds, Series due Aug. 15, 2015 and $250 million principal amount of 4.850% First Mortgage Bonds, Series due Aug. 15, 2040	NSP-Minnesota Form 8-K dated Aug. 4, 2010	001-31387	4.01
4.12*	Supplemental Trust Indenture dated as of Aug. 1, 2012 between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA, as successor Trustee, creating $300 million principal amount of 2.15% First Mortgage Bonds, Series due Aug. 15, 2022 and $500 million principal amount of 3.40% First Mortgage Bonds, Series due Aug. 15, 2042	NSP-Minnesota Form 8-K dated Aug. 13, 2012	001-31387	4.01
4.13*	Supplemental Trust Indenture dated as of May 1, 2013 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $400 million principal amount of 2.60% First Mortgage Bonds, Series due May 15, 2023	NSP-Minnesota Form 8-K dated May 20, 2013	001-31387	4.01
4.14*	Supplemental Trust Indenture dated as of May 1, 2014 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $300 million principal amount of 4.125% First Mortgage Bonds, Series due May 15, 2044. (Exhibit 4.01 to NSP-Minnesota Form 8-K dated May 13, 2014 (file no. 001-31387))	NSP-Minnesota Form 8-K dated May 13, 2014	001-31387	4.01

4.15*	Supplemental Indenture dated as of Aug. 1, 2015 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $300 million principal amount of 2.20% First Mortgage Bonds, Series due Aug. 15, 2020 and $300 million principal amount of 4.00% First Mortgage Bonds, Series due Aug. 15, 2045	NSP-Minnesota Form 8-K dated Aug. 11, 2015	001-31387	4.01
4.16*	Supplemental Trust Indenture dated as of May 1, 2016 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $350 million principal amount of 3.600% First Mortgage Bonds, Series due May 15, 2046	NSP-Minnesota Form 8-K dated May 31, 2016	001-31387	4.01
4.17*	Supplemental Indenture dated as of Sept. 1, 2017 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor trustee, creating $600 million principal amount of 3.60% First Mortgage Bonds, Series due Sept. 15, 2047	NSP-Minnesota Form 8-K dated Sept. 13, 2017	001-31387	4.01
10.01*+	Xcel Energy Inc. Nonqualified Pension Plan (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.02
10.02*+	Xcel Energy Senior Executive Severance and Change-in-Control Policy (2009 Amendment and Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.05
10.03*+	Xcel Energy Inc. Non-Employee Directors Deferred Compensation Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.08
10.04*+	Form of Services Agreement between Xcel Energy Services Inc. and utility companies	Xcel Energy Inc. Form U5B dated Nov. 16, 2000	001-03034	H-1
10.05*+	Xcel Energy Inc. Supplemental Executive Retirement Plan as amended and restated Jan. 1, 2009	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.17
10.06*	Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota	NSP-Wisconsin Form S-4 dated Jan. 21, 2004	333-112033	10.01
10.07*+	First Amendment to Exhibit 10.02 dated Aug. 26, 2009	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2009	001-03034	10.06
10.08*+	Xcel Energy Inc. Executive Annual Incentive Award Plan Form of Restricted Stock Agreement	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2009	001-03034	10.08
10.09*+	Xcel Energy Inc. Executive Annual Incentive Plan (as amended and restated effective Feb. 17, 2010)	Xcel Energy Inc. Definitive Proxy Statement dated April 6, 2010	001-03034	Schedule 14A
10.10*+	Xcel Energy Inc. 2005 Long-Term Incentive Plan (as amended and restated effective Feb. 17, 2010)	Xcel Energy Inc. Definitive Proxy Statement dated April 6, 2010	001-03034	Schedule 14A
10.11*+	Stock Equivalent Plan for Non-Employee Directors of Xcel Energy Inc. as amended and restated effective Feb. 23, 2011	Xcel Energy Inc. Definitive Proxy Statement dated April 5, 2011	001-03034	Schedule 14A
10.12*+	Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.07
10.13*+	First Amendment to Exhibit 10.12 effective Nov. 29, 2011	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2011	001-03034	10.17
10.14*+	Second Amendment to Exhibit 10.02 dated Oct. 26, 2011	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2011	001-03034	10.18
10.15*+	First Amendment to Exhibit 10.09 dated Feb. 20, 2013	Xcel Energy Inc. Form 10-Q for the quarter ended March 31, 2013	001-03034	10.01
10.16*+	Fourth Amendment to Exhibit 10.02 dated Feb. 20, 2013	Xcel Energy Inc. Form 10-Q for the quarter ended March 31, 2013	001-03034	10.02
10.17*+	First Amendment to Exhibit 10.10 dated May 21, 2013	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2013	001-03034	10.21
10.18*+	Second Amendment to Exhibit 10.12 dated May 21, 2013	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2013	001-03034	10.22
10.19*+	Xcel Energy Inc. 2005 Long-Term Incentive Plan Form of Long-Term Incentive Award Agreement	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2013	001-03034	10.23
10.20*+	Xcel Energy Inc. 2015 Omnibus Incentive Plan	Xcel Energy Inc. Definitive Proxy Statement dated April 6, 2015	001-03034	Schedule 14A
10.21*+	Stock Equivalent Program for Non-Employee Directors of Xcel Energy Inc. under the Xcel Energy Inc. 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 8-K dated May 20, 2015	001-03034	10.02
10.22*+	Form of Xcel Energy Inc. 2015 Omnibus Incentive Plan Award Agreement and Award Terms and Conditions under the Xcel Energy Inc. 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 8-K dated May 20, 2015	001-03034	10.03
10.23*+	Xcel Energy Inc. 2015 Omnibus Incentive Plan Form of Award Agreement	Xcel Energy inc. Form 10-K for the year ended Dec. 31, 2015	001-03034	10.28
10.24*+	Xcel Energy Inc. Executive Annual Incentive Award Sub-plan pursuant to the Xcel Energy Inc. 2015 Omnibus Incentive Plan	Xcel Energy inc. Form 10-K for the year ended Dec. 31, 2015	001-03034	10.29
10.25*+	Fifth Amendment Exhibit 10.02 dated May 3, 2016	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2016	001-03034	10.01
10.26*	Second Amendment and Restated Credit Agreement, dated as of June 20, 2016 among NSP-Minnesota, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association and the Bank of Tokyo-Mitsubishi UFJ, Ltd., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 20, 2016	001-03034	99.02
10.27*+	Third Amendment to Exhibit 10.12 dated Sept. 30, 2016	Xcel Energy inc. Form 10-Q for the quarter ended Sept. 30, 2016	001-03034	10.01
10.28*+	Form of Xcel Energy, Inc. 2015 Omnibus Incentive Plan Award Agreement and Award Terms and Conditions under the Xcel Energy inc. 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2016	001-03034	10.27

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10.29*+	Fourth Amendment to Exhibit 10.12 dated Oct. 23, 2017	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2017	001-03034	10.1
10.30*+	Sixth Amendment to Exhibit 10.02 dated Feb. 22, 2018	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2017	001-03034	10.30
10.31*+	Seventh Amendment to Exhibit 10.02 dated May 7, 2018	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2018	001-03034	10.01
10.32*+	Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	001-03034	10.34
10.33*+	Form of Xcel Energy Inc. 2015 Omnibus Incentive Plan Award Agreement Terms and Conditions under the Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	001-03034	10.35
10.34*+	Stock Program for Non-Employee Directors of Xcel Energy Inc. as Amended and Restated on Dec. 12, 2017 under the 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	001-03034	10.36
23.01	Consent of Independent Registered Public Accounting Firm.			
31.01	Principal Executive Officer's certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.			
31.02	Principal Financial Officer's certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.			
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.			
101	The following materials from NSP-Minnesota's Annual Report on Form 10-K for the year ended Dec. 31, 2018 are formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income, (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Balance Sheets, (v) the Consolidated Statements of Stockholder's Equity, (vi) Notes to Consolidated Financial Statements, (vii) document and entity information, and (viii) Schedule II.			

SCHEDULE II

NSP-MINNESOTA AND SUBSIDIARIES VALUATION AND QUALIFYING ACCOUNTS YEARS ENDED DEC. 31

	Allowance for bad debts		
(Millions of Dollars)	2018	2017	2016
Balance at Jan. 1	$ 21.3	$ 20.0	$ 20.8
Additions Charged to Costs and Expenses	16.2	15.7	15.0
Additions Charged to Other Accounts [(a)]	4.1	3.8	4.2
Deductions from Reserves [(b)]	(18.1)	(18.2)	(20.0)
Balance at Dec. 31	$ 23.5	$ 21.3	$ 20.0

(a) Recovery of amounts previously written off.

(b) Deductions relate primarily to bad debt write-offs.

Item 16 — Form 10-K Summary

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this annual report to be signed on its behalf by the undersigned thereunto duly authorized.

NORTHERN STATES POWER COMPANY
(A MINNESOTA CORPORATION)

Feb. 22, 2019

/s/ ROBERT C. FRENZEL
Robert C. Frenzel
Executive Vice President, Chief Financial Officer and Director
(Principal Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities on the date indicated above.

/s/ BEN FOWKE	/s/ CHRISTOPHER B. CLARK
Ben Fowke	Christopher B. Clark
Chairman, Chief Executive Officer and Director	President and Director
(Principal Executive Officer)	
/s/ ROBERT C. FRENZEL	/s/ JEFFREY S. SAVAGE
Robert C. Frenzel	Jeffrey S. Savage
Executive Vice President, Chief Financial Officer and Director	Senior Vice President, Controller
(Principal Financial Officer)	(Principal Accounting Officer)
/s/ DAVID L. EVES	
David L. Eves	
Executive Vice President and Director	

SUPPLEMENTAL INFORMATION TO BE FURNISHED WITH REPORTS FILED PURSUANT TO SECTION 15(D) OF THE ACT BY REGISTRANTS WHICH HAVE NOT REGISTERED SECURITIES PURSUANT TO SECTION 12 OF THE ACT

NSP-Minnesota has not sent, and does not expect to send, an annual report or proxy statement to its security holder.

Nonregulated Business Activity Allocations (Minnesota)
2020 Test Year Budget

Allocation	Allocation Method	Reasonableness of Allocation Method	Allocation Percent
Labor Related Overhead	Based on employee related expenses, office equipment, and supervision of the service provider.	This allocation represents the relationship between the costs to support labor with labor costs, and is applied to loaded labor.	13.4588%
Corporate Residual	Two-Factor Allocator based on number of employees and revenues relative to NSPM totals.	This allocation represents a fair comparison of the non-regulated business' relative size to the total company and is applied to the prior year actual pool of expenses incurred on behalf of the corporation	HomeSmart - 0.4773% Customer Owned Street Lighting - 0.1172% Infowise - 0.0017% ConnectSmart - 0.0023%