Direct Testimony and Schedules
Karen L. Everson

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of Northern States Power Company,
a Minnesota corporation d/b/a Xcel Energy
Jurisdictional Cost Allocation Matters

Case Nos. PU-12-813, PU-13-706, PU-13-707, PU-13-708,
PU-13-742, PU-13-743, PU-13-194, PU-13-195
Exhibit___(KLE-1)

Costs of Legal Separation, Implementation of Pseudo Separation, and Jurisdictional Allocation

July 15, 2017

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Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Karen L. Everson and I am the Director, Utility Accounting for Xcel Energy Services Inc. ("XES"). XES is the service company for the Xcel Energy Inc. holding company system, and provides services to all of the operating utility subsidiaries of Xcel Energy Inc., including Northern States Power Company-Minnesota (NSPM or Xcel Energy or the Company).

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have more than 20 years of employment experience with XES and Northern States Power Company. I have been the Director, Utility Accounting since March 2010. My resume is included as Exhibit___(KLE-1), Schedule 1.

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

A. I am testifying in support of Xcel Energy's Application for Consideration of a Resource Treatment Framework (the RTF Application) filed on December 31, 2016 with the North Dakota Public Service Commission (Commission) and the Minnesota Public Utilities Commission (MPUC). My Direct Testimony provides cost estimates for implementation of the Legal Separation alternative discussed in the RTF Application, provides detail about the accounting and allocation procedures that would be necessary to implement Pseudo Separation, and provides background information about the NSPM/NSPW Interchange Agreement.

Q. PLEASE PROVIDE AN OVERVIEW OF THE REMAINDER OF YOUR TESTIMONY.

A. My testimony is organized as follows:

- Section II provides a brief overview of the RTF Application and background information, including information about the NSPM/NSPW Interchange Agreement, to provide context for the rest of the testimony.
- Section III provides information about some of the estimated costs of implementation of Legal Separation.
- Section IV provides information about the accounting and allocation procedures necessary to implement Pseudo Separation, particularly cost recovery and accounting mechanisms.

II. OVERVIEW AND BACKGROUND

A. Overview of Allocation Concepts

Q. HOW ARE THE COSTS AND BENEFITS OF THE NSP SYSTEM'S GENERATION RESOURCES ALLOCATED CURRENTLY?

A. Currently, the NSP System is planned and operated as an integrated generation and transmission system, with costs allocated to each of the jurisdictions that are served by the system based on total system costs and revenues. The allocation of costs between NSPM and NSPW is governed by an Interchange Agreement. The share of NSP costs allocated to NSPM pursuant to that Interchange Agreement are then allocated to NSPM's three state jurisdictions—Minnesota, North Dakota, and South Dakota.

Q. PLEASE DESCRIBE HOW THE NSPM-NSPW INTERCHANGE AGREEMENT WORKS.

A. The NSPM-NSPW Interchange Agreement is a rate schedule on file with the Federal Energy Regulatory Commission (FERC). The two operating companies—NSPM and NSPW—are the parties to the Interchange

Agreement. The Interchange Agreement provides NSPM and NSPW with reciprocal rights of use of each other's facilities, and allows them to plan and operate their power supply facilities as an integrated system. The Interchange Agreement establishes a Coordinating Committee, on which NSPM and NSPW each have two representatives, that is responsible for: coordinating the planning and design of generation and transmission facilities over a ten-year horizon; coordinating the operation and maintenance of the generation and transmission facilities; administering procedures for determining the amounts of power and energy sold among the parties; and administering the monthly charges under the formula rates contained in the Interchange Agreement.

Approximately 85 percent of the NSP System costs are allocated to NSPM and 15 percent are allocated to NSPW. This is because approximately 85 percent of the load on the integrated system is NSPM load and 15 percent is NSPW load. The exact allocation percentages are determined by formulas set forth in the Interchange Agreement. The objective of the charges in the Interchange Agreement is to compensate the party selling power and energy for its full fixed costs, including return, and its full variable costs of producing and transmitting power and energy. While only one operating company has title to, or contracts for, any given generation or transmission asset, the Interchange Agreement provides the means by which both NSPM and NSPW share the cost of developing, operating, and maintaining all generation and transmission facilities that comprise the NSP System. Because the Interchange Agreement is a FERC jurisdictional federal tariff, it is overseen and regulated by FERC.

The Interchange Agreement is the means by which Wisconsin and Michigan fully participate in the NSP System, taking full advantage of the benefits of

scale and reliability that come with operation of the NSP System as an integrated whole.

Q. ONCE NSP SYSTEM COSTS ARE ALLOCATED TO NSPM PURSUANT TO THE INTERCHANGE AGREEMENT, HOW ARE THEY THEN ALLOCATED TO NSPM'S THREE STATE JURISDICTIONS—MINNESOTA, NORTH DAKOTA, AND SOUTH DAKOTA?

A. Unlike the inter-corporate relationships managed through the Interchange Agreement and regulated by FERC, inter-jurisdictional costs within a single corporate entity are generally managed through state regulatory approval of ratemaking factors.

Currently, fixed production and transmission costs are generally allocated among the three jurisdictions using "The Sum of 12 Monthly Coincident Peak" (12CP Method). Variable production costs are generally allocated among the three jurisdictions using energy.

Q. PLEASE EXPLAIN THE 12CP METHOD.

A. Under the 12CP Method, NSPM first determines each jurisdiction's peak demand, measured in kilowatts (kW), coincident with NSP System peaks, for each of the 12 months of the year. The monthly NSP System peaks for each state are then summed, and each state's allocation is determined by dividing the state's 12-month total by the NSPM 12-month total. The 12CP Method allocates the costs of generating capacity and transmission capability to each jurisdiction according to the capacity necessary to generate energy and provide transmission service to the jurisdiction. By design, the 12CP Method allocates 100 percent of system costs to the individual state jurisdictions, allowing the

Company to fully recover its cost of service. The Minnesota, North Dakota, and South Dakota state regulatory commissions have all approved the 12CP Method. The fact that all three states use the same allocation methodology ensures uniform treatment of costs across the jurisdictions.

Q. WHAT IS THE MISO MARKET OVERLAY?

A. The Mid-Continent Independent System Operator, Inc. (MISO) administers a large wholesale electricity market spanning 15 states, including the NSP System's entire service area. The MISO market operates as a clearing house intended to solve for the most economic way to match load (demand) and generation (supply). Within MISO, market participants such as the NSP System sell all energy generation into the market and purchase all energy needs from the market. The NSP System sells power generation to MISO (a credit to the NSP System), and purchases load from MISO (a debit to the NSP System). At any given time, the NSP System is involved in many transactions in the MISO energy market. Each day, the NSP System "settles" with the market, i.e., offset its debits and credits. There are many complexities to this, some of which I will describe in more detail below. For purposes of this general overview of the allocation process, it is sufficient to understand that generally all the income associated with the NSP System's generation assets is received through the MISO settlement process. As a result, NSPM's allocation of costs and benefits to the three jurisdictions is closely intertwined with the MISO settlement process.

B. Overview of the RTF Application

Q. AT A BROAD LEVEL, WHAT IS THE PURPOSE OF THE RTF APPLICATION?

A. At a broad level, the Company is proposing a more separate future between

North Dakota and the remainder of the NSP System, in order to address past and anticipated future disagreements between the NSP System states regarding the resources serving the NSP System. Company witness Mr. Aakash H. Chandarana discusses this at length in his Direct Testimony.

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSALS IN THE RTF APPLICATION.

A. The RTF Application presented a "Framework" in which a Legacy System would be established, and then as new generation resources come along, the costs and benefits of those resources would be separated: when a resource need arises in North Dakota, that need will be met by a resource sized for, dedicated to serve only, and fully recovered in North Dakota; and when a resource need arises in the remainder of the NSP System, that need will be met by a resource sized for, dedicated to serve only, and fully recovered in the remainder of the NSP System. The Company identified a number of approaches by which this separation could be implemented. The main two approaches on which the Company focuses in the RTF Application are Pseudo Separation and Legal Separation.

C. Legal Separation

Q. WHAT IS LEGAL SEPARATION?

A. Legal Separation refers to creating a separate operating company to serve our North Dakota customers.

Q. WHAT IS THE CORPORATE STRUCTURE BY WHICH LEGAL SEPARATION WOULD BE IMPLEMENTED?

A. Legal Separation requires the Company to invest the costs of creating a new, separate company within the Xcel Energy corporate structure. As a shorthand, this new company can be called NSP Dakota, or NSPD.

Q. WHAT WOULD THE SIZE AND SCOPE OF NSPD BE?

A. Our North Dakota customers make up about five percent (approximately 500 MW) of the NSP System while our Minnesota customers make up approximately 75 percent (approximately 7,500 MW) of the NSP System. Because NSPD would include only the revenues, expenses, rate base, and resources necessary to serve North Dakota customers, it would be considerably smaller than NSPM in population served, employees, resources, and capitalization than NSPM is now.

D. Pseudo Separation

Q. AT A HIGH LEVEL, WHAT IS PSEUDO SEPARATION?

A. Pseudo Separation refers to a structure under which we would separate the generation portfolios serving North Dakota and the remainder of the NSP System, without changing the corporate structure of NSPM, by assigning the costs and benefits of specific resources to the states that support them and developing separate resources for non-approving states as necessary. Pseudo Separation would have no impact on the transmission portion of the NSP System.

Q. HOW WOULD PSEUDO SEPARATION WORK?

A. Pseudo Separation would account for generation activities on a generator level rather than on the system-wide level at which we allocate costs and revenues today. This would be accomplished by establishing accounting for and

allocation of the various benefits and burdens associated with each individual resource.

In Pseudo Separation, we would identify the cost and revenue portions of individual generation resources (including power purchase agreements (PPAs)) and apply specific allocators to directly assign or allocate the costs and benefits to cost-causative and supportive jurisdictions. Pseudo Separation would essentially reallocate the economic impacts of the MISO market overlay to particular states through regulatory ratemaking.

Q. WHAT TYPES OF COSTS AND BENEFITS WOULD REQUIRE ALLOCATION UNDER PSEUDO SEPARATION?

A. In general, for each resource, a bundle of costs or burdens and a bundle of revenues or benefits would need to be identified, accounted for, and allocated. The specific costs/burdens and revenues/benefits to be allocated would vary depending on the particular resource. For a PPA, the costs/burdens include the PPA price, and for Company-owned resources, the costs/burdens include capital and operations and maintenance (O&M). Revenues/benefits would include the revenue from the sale of output into the MISO energy market or of unit-specific capacity; resource planning/adequacy attributes (such as capacity value and energy); and other values (such as environmental credits).

Q. HOW WOULD COSTS BE ALLOCATED UNDER PSEUDO SEPARATION?

A. To be implemented, Pseudo Separation would require some initial interstate decisions regarding how to assign or allocate the benefits and burdens of individual resources. While the specific allocation methodology and approach will vary for each type of resource and category of cost or revenue, at a high

level, appropriate and equitable allocation methods under Pseudo Separation would be guided by the following objectives:

1. Representative of Costs/Revenue—The allocation methods should be designed to capture cost/revenue causation to the extent possible.
2. Predictability—The actual allocation of costs for a given year should be predictable and forecastable ahead of time using either historical trends and/or projected data.
3. System Cost Recoverability—The allocation methods should provide an opportunity for Xcel Energy to recover its approved system costs across all jurisdictions.

By design, jurisdictional allocation under a Pseudo Separation structure would seek to allocate 100 percent of the costs and benefits for each resource to each of the individual state jurisdictions served by the system. I provide additional details regarding proposed resource allocations under Pseudo Separation and examples of such allocations in Section IV below.

Q. AT A BROAD LEVEL, HOW WOULD PSEUDO SEPARATION ACCOUNT FOR THE MISO MARKET OVERLAY?

A. Under the Pseudo Separation structure, MISO costs and revenues would be separately tracked, with revenues from sales of energy into the MISO market being assigned to the specific jurisdiction(s) paying for the energy resource. MISO load costs, or purchases of energy from the MISO market, would be allocated to specific jurisdictions based on load-ratio share. For example, the Minnesota jurisdiction would be allocated MISO load costs based on the ratio of Minnesota jurisdiction calendar month sales to NSP System calendar month sales. The North Dakota jurisdiction would be allocated MISO load costs

based on the ratio of North Dakota jurisdiction billing month sales to NSP system billing month sales.

Q. WHAT CHALLENGES DO YOU ANTICIPATE WITH PSEUDO SEPARATION?

A. Pseudo Separation presents a number of significant challenges. The challenge that is most pertinent to my testimony is that it will require creation of a new accounting and allocation structure, which will require initial work to develop and refine. Pseudo Separation could add significant complexity to our accounting and ratemaking, depending on the number of generating resources to be separately assigned. Finally, there are certain situations in which implementation of the Pseudo Separation structure would be difficult—one example would be where different units of a single generating resource need to be assigned separately.

Q. DOES XCEL ENERGY HAVE ANY PRIOR EXPERIENCE WITH IMPLEMENTING A PSEUDO SEPARATION STRUCTURE?

A. No. While the concept of Pseudo Separation originally came from the pricing zone concept in natural gas operations, of which Xcel Energy has some experience, we do not have any experience with implementation of such a structure in the context of an integrated electric system.

III. ESTIMATED COSTS OF LEGAL SEPARATION

Q. HAS THE COMPANY ANALYZED THE COSTS ASSOCIATED WITH CREATING AND IMPLEMENTING A NORTH DAKOTA OPERATING COMPANY?

A. Yes. First, there would be up-front transaction costs incurred for the creation and regulatory approvals necessary to establish NSPD. Then there would be

ongoing costs, principally: dedicated management of the separate company, with associated administrative and general ("A&G") costs; the cost of separate financing of NSPD operations and investments; revised service company allocations to reflect NSPD as a stand-alone business; and regionally-shared transmission costs.

Q. WHICH OF THESE COST CATEGORIES WILL YOU DISCUSS?

A. I will provide information supporting our cost estimates for two of the categories: NSPD Oversight and A&G, and Service Company Allocations.

Q. HOW CERTAIN ARE THE COST ESTIMATES YOU WILL PRESENT?

A. There are still many significant unresolved questions about NSPD, as described in the Direct Testimony of Company witness Mr. Richard D. Starkweather. Until those issues are resolved and a Legacy System is established, the costs of Legal Separation will remain difficult to estimate with precision.

A. Oversight Costs

Q. AS YOU STARTED TO ANALYZE THE COSTS OF DEDICATED OVERSIGHT FOR NSPD, WHAT ASSUMPTIONS DID YOU MAKE?

A. Some general assumptions about how NSPD would be structured and would function are set forth in Mr. Starkweather's Direct Testimony. For purposes of estimating oversight costs, it was assumed that NSPD would require one separate corporate officer not already in place—a president. The president would be supported by an executive assistant. Most other corporate leadership functions would be done by current employees of XES, with the cost of that work direct-allocated to NSPD, or would be done by currently-existing NSPM employees in North Dakota who would be transferred to NSPD. It was also

assumed that, similar to the existing arrangement where NSPW leases office space in Wisconsin's capital, Madison, it would be beneficial for NSPD to have office space in Bismarck.

In addition, it was assumed that of the over 100 existing NSPM employees located in North Dakota, some would become employed with NSPD and others would remain XES or NSPM employees. For purposes of this analysis, we have not detailed which employees would be hired or would move between companies; since the implementation of Legal Separation would be several years out, it is too early to make those determinations. Rather, we assessed the likely incremental resource needs compared to current staffing levels. The largest category of incremental costs would be related to the accounting function: additional staffing would be necessary for the settlement and accounting of MISO invoices, SEC and FERC reporting, and business area support for the new NSPD.

Finally, it was assumed that additional costs would be incurred in connection with paying vendors such as accounting firms for services including external accounting and auditing, fees connected to formula rate management, and actuarial and other benefit-related services.

Q. WHAT ARE THE TOTAL COST IMPACTS YOU ESTIMATE WOULD BE ASSOCIATED WITH DEDICATED OVERSIGHT OF A SEPARATE NSPD ENTITY?

A. The Company estimates that dedicated oversight, and A&G expense, for a new NSPD, would cost approximately $1.4 million.

Q. WHAT IS THE BASIS FOR YOUR $1.4 MILLION ESTIMATE?

A. We estimate the costs associated with a separate operating president and support staff for NSPD at approximately $460,000. This estimate was loosely based on similar costs for NSPW, with annual escalation of three percent to the year 2020. We estimate the annual cost for office space in Bismarck at $55,000.

To estimate incremental costs for the accounting function, we evaluated the additional positions that would be necessary as a result of the new NSPD and the grade level of those positions. Using Xcel's current salary structure, an annual escalation of three percent to the year 2020, and an estimated labor load percent for pension, benefits, and payroll taxes, we estimate incremental labor costs of $530,000.

We estimated the additional costs for external services at a total of $390,000.

A summary of the incremental costs is provided in Table 1 below. Exhibit___(KLE-1), Schedule 2, provides the detailed incremental cost calculation for each component.

Table 1

Description	Total Ongoing Costs
Executive Management	$515,000
Incremental Labor	$530,000
Outside Services	$390,000
Totals	$1,435,000

Q. HOW CERTAIN IS THE COMPANY ABOUT THIS ESTIMATE OF LIKELY FUTURE COSTS FOR OVERSIGHT AND A&G?

A. The Company believes its $1.4 million estimate is a reasonable approximation of the incremental costs to be incurred; however, this estimate is subject to

change as more information is gathered. For example, since several departments (e.g. Revenue Accounting and Capital Asset Accounting) already maintain their records by jurisdiction, we think that significant changes would not be needed to move from a jurisdictional calculation to a separate operating company calculation, and that any required changes could be performed with existing staff resources. Another example is Information Technology (IT) costs—our estimate does not include any expense for additional IT equipment, but it is possible that the additional accounting work discussed above could require significant incremental investment in IT equipment.

B. Service Company Allocations

Q. HOW ARE COSTS BILLED FROM XES TO OPERATING COMPANIES?

A. As I mentioned above, XES is the service company for the Xcel Energy Inc. holding company system, and provides services to all of the operating utility subsidiaries of Xcel Energy Inc. Ongoing costs incurred by XES for services rendered to a specific operating company are billed in two ways: 1) Direct Charges and 2) Allocated Charges. 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. HOW ARE INDIRECT XES COSTS ALLOCATED TO THE OPERATING COMPANIES?

A. Allocated charges are billed from the service company to NSPM and other affiliates pursuant to a Service Agreement. Attached as Exhibit___(KLE-1), Schedule 3 is the Company's response to Commission Data Request No. 2-12, which contains a copy of the Service Agreement. The Service Agreement specifies, for each type of cost, a formula that will be used to allocate the cost

among the affiliate companies. Most of the formulas are based on a ratio comparing the size of some attribute of the operating company to the cumulative size of that attribute for all of the operating companies. Many of the types of indirect costs are allocated using the "General Allocator," which is a three-factor formula comprised of the average of the Revenue Ratio, Employee Ratio, and Total Assets Ratio. For NSPM, the XES costs billed to NSPM are then allocated to each of the NSPM jurisdictions based on currently-approved ratemaking allocation methodologies.

Q. WHAT ASSUMPTIONS DID YOU MAKE IN ANALYZING SERVICE COMPANY ALLOCATIONS FOR THE PROPOSED NSPD?

A. First, there was no need to analyze XES direct charges for NSPD as part of this analysis—to the extent that such additional direct costs would be incurred, they are already addressed elsewhere in the rest of the discussion regarding the costs of legal separation in my testimony, Mr. Starkweather's testimony, and Company witness Mr. Stephen J. Beuning's testimony.

As to indirect costs, we assumed an NSPD stand-alone entity would likely enter into its own services agreement with XES. The service agreement would specify allocation formulas, similar to the way the current Service Agreement for NSPM does. The new service agreement would be subject to regulatory oversight consistent with the laws of each jurisdiction. Because it would be impractical to estimate values for NSPD for every one of the many attributes used in the allocation process, the Company analyzed and estimated eight attributes that would be used in the most important ratios and thus would affect the majority of the allocated charges. The eight attributes were:

1) Gross plant,
2) Net plant,
3) Total assets,
4) Revenues,
5) Customer count,
6) Number of employees,
7) Number of computers,
8) Mwh generation.

For each of these eight attributes, we estimated the values for NSPD as if it were a stand-alone entity.

Then, because NSPD would be a carve-out from NSPM, a corresponding reduction to the attributes was assumed for the remaining NSPM. The allocations were recalculated for 2016, based on the current allocation methods and ratios, to determine the impact of a separate NSPD (these allocations may not be applicable once NSPD is created). For those allocations based on a statistic not calculated for a separate NSPD, an estimate was made of what those costs would be. Overall results were reviewed for reasonableness. A comparison was then made to the estimated indirect costs currently allocated from NSPM and the indirect allocations to the separate NSPD from the service company. Exhibit___(KLE-1), Schedule 4, identifies the statistics that were assumed and the resulting impact on the allocated charges.

Q. WHAT CONCLUSION DID YOU DRAW FROM SCHEDULE 4?

A. In sum, we anticipate that Service Company Allocations would result in a revenue requirement decrease to North Dakota of approximately $9 million,

with a corresponding increase to the remaining NSPM. This includes an escalation of the 2016 costs to 2020 levels.

Q. WHY IS THE RESULT OF LEGAL SEPARATION, AS TO SERVICE COMPANY ALLOCATIONS, A DECREASE FOR NORTH DAKOTA?

A. The NSPD stand-alone entity is expected to have very limited assets—as Mr. Starkweather describes, we assume it would have no generation or transmission assets. As a result, the NSPD stand-alone entity would have very small values for many of the attributes used in allocation of indirect Service Company costs, such as Total Assets and Gross Plant—significantly smaller than the proportion allocated to the North Dakota electric jurisdiction under currently approved ratemaking allocation methodologies.

Q. DOES THE $9 MILLION FIGURE YOU REFERRED TO ABOVE MEAN THAT NORTH DAKOTA WOULD SEE A $9 MILLION REDUCTION IN ITS COSTS?

A. No. There would be some offset of this reduction in the production rate formula as discussed in Company witness Mr. Charles R. Burdick's Direct Testimony.

Q. WHAT PRESENT UNKNOWNS COULD AFFECT THE ACCURACY OF YOUR ESTIMATE OF THE SERVICE COMPANY ALLOCATIONS THAT WILL RESULT FROM LEGAL SEPARATION?

A. Perhaps the two biggest assumptions are that the separate NSPD will have no generation or transmission assets, and that the current allocation methodology would remain in place. If those assumptions, or other assumptions on which the analysis is built, are incorrect, the Service Company Allocations costs could be significantly different.

IV. IMPLEMENTATION OF PSEUDO SEPARATION

Q. WHAT STEPS WOULD BE REQUIRED TO IMPLEMENT PSEUDO SEPARATION?

A. Pseudo Separation would require a number of steps and modifications from existing practice to be implemented:

1) New accounting methods and allocations would need to be developed, implemented, and managed over time.
2) Treatment of distributed energy resources, such as Behind the Meter Generation, would need to be evaluated.
3) The existing NSPM/NSPW Interchange Agreement would need to be modified.
4) There are many transmission considerations that would have to be analyzed.
5) There are many resource planning issues that would need to be addressed. At a high level, it would be necessary to plan for the load-serving needs and energy priorities of each jurisdiction, and establish separate resource tables for each.

I will focus on the first three of these issues. The transmission issues under Pseudo Separation are addressed in the Direct Testimony of Mr. Beuning, and the resource planning issues are addressed in the Direct Testimony of Company witness Mr. Philip Joseph "P.J." Martin.

A. Cost Recovery and Accounting Mechanisms

Q. WHAT COST RECOVERY AND ACCOUNTING METHODS WOULD NEED TO BE DEVELOPED TO IMPLEMENT PSEUDO SEPARATION?

A. For each new or disputed resource, Pseudo Separation would require an identification of the bundle of benefits and burdens related to that resource, including costs (such as the PPA price for contracted resources or capital and operations and maintenance (O&M) of Company-owned resources); revenues (from sale of output into the MISO energy market or of unit-specific capacity); resource planning/adequacy attributes (such as capacity value and energy); and other values (such as environmental credits). It would be necessary to develop specific accounting for each of these bundles of benefits and burdens and to develop allocation methodologies to assign the benefits and burdens to each jurisdiction in an equitable way based on cost-causation. The jurisdictional allocation methodologies would then need to be applied in the context of ratemaking to ensure just and reasonable cost and revenue allocations for individual generation resources. There are a number of categories of costs/burdens and revenues/benefits that would need to be identified, tracked, and allocated.

Q. CAN THESE METHODOLOGIES BE IMPLEMENTED USING THE COMPANY'S CURRENT ACCOUNTING SYSTEM?

A. Yes. The Company's SAP General Ledger system contains certain fields and other hierarchical structures that can be used to track costs/burdens and revenues/benefits to individual generation resources. But the Company might need to invest in other aspects of its IT infrastructure in order to support these complex accounting and allocation processes.

Q. WILL THE JURISDICTIONAL ALLOCATION METHODOLOGIES YOU DESCRIBE BELOW BE SUFFICIENTLY CLEAR AND DETAILED?

A. Yes. All of the proposals set forth below are intended to be fully auditable in a rate case or other rate proceeding so that as rates are set, each jurisdiction can be sure that the rates are built upon a properly supported, reasonable, and trackable allocation. The proposals are divided into two sections: 1) energy-related revenue and expense, i.e., those items generally recovered through the Fuel Cost Rider (FCR) and 2) plant, O&M, and other items generally recovered through a base rate proceeding.

Q. ARE THESE ALLOCATION AND ACCOUNTING PROPOSALS SET IN STONE?

A. Not at all. My testimony describes how the Company thinks Pseudo Separation could work, from an accounting and allocation perspective, but we are open to discussion on any of the proposals set forth below.

1. Energy-Related Revenue and Expense

Q. WHAT ARE THE CURRENT COST-SHARING METHODS FOR ENERGY-RELATED REVENUE AND EXPENSE?

A. Costs are accumulated for the NSP System for items recovered through the FCR. Adjustments are made to the NSP System costs for each jurisdiction as necessary. For example, the Commission allows recovery of MISO Schedule 16 and 17 costs through the FCR whereas the MPUC dictates these costs are to be recovered in base rates. The system costs are then allocated to each jurisdiction based on the ratio of the jurisdiction to the NSP System. Calendar month sales are used as the allocator for Minnesota whereas billed month sales are used as the allocator for North Dakota.

a. Fuel Expense

Q. HOW WOULD FUEL EXPENSE BE ALLOCATED AND ACCOUNTED FOR UNDER PSEUDO SEPARATION?

A. Fuel expense from the Legacy System will be shared across the system using current cost-sharing methods. Fuel expense from new resource additions will be separately identified and assigned to the specific jurisdiction(s) paying for the energy resource. The Company has capacity in its accounting system to identify fuel expense from new resource additions and assign those expenses to the appropriate jurisdiction.

b. Purchased Power Expense

Q. HOW WOULD PURCHASED POWER EXPENSE BE ALLOCATED AND ACCOUNTED FOR UNDER PSEUDO SEPARATION?

A. It would be very similar to how fuel expense would be handled. Non-MISO purchased power expense from the Legacy System will be shared across the system using current cost-sharing methods. Non-MISO purchased power expense from new contracts will be separately identified and assigned to the specific jurisdiction(s) paying for the energy resource. The Company has capacity in its accounting system to identify purchased power expense from new resource additions and assign those expenses to the appropriate jurisdiction.

c. MISO Revenue and Expense

Q. PLEASE DESCRIBE HOW THE COMPANY WOULD ALLOCATE MISO REVENUE AND EXPENSE UNDER THE PSEUDO SEPARATION STRUCTURE?

A. As I briefly described above, NSPM sells energy generation into the MISO market and purchases energy needs from the MISO market. Under the Pseudo

Separation approach, MISO revenues and expenses related to new resource additions that are not shared across the system will be identified and assigned to the specific jurisdiction(s) paying for the energy resource. All MISO load costs or purchases of energy from the MISO market, and any MISO revenues or expenses that cannot be separately identified by resource or contract, will be shared across the system using current cost-sharing methods.

Q. DOES THE COMPANY HAVE THE CAPABILITY, FROM AN ACCOUNTING POINT OF VIEW, TO IMPLEMENT THIS?

A. Yes. As I described above, NSPM engages in a complex process of settling the credits and debits from these transactions. On a daily basis, MISO provides initial and revised settlement statements for operating days ranging from 7, 14, 55 and 105 days in the past. Settlement statements provide net dollar amounts totaled by day for each of 60 charge types billed on the Market invoice. In addition to net dollar totals, MISO provides market participants with the billing information necessary to calculate position-level detail (i.e., who owes who) at each settlement interval. Position types include Resources, Load Zones, Reserve Zones, Physical/Financial Bilateral Transactions, Virtual Transactions and Financial Transmission Rights. Most market transactions occur on the hour or five-minute interval, while others occur daily, monthly or yearly. It is the burden of the market participant to calculate, validate and record the granular settlements details required by various accounting, reporting and analytical functions.

NSPM uses PCI GenManager settlement software to process MISO settlement statements and validate invoices through a shadow settlement process. The process involves parsing settlement statements, reconstructing daily charges

and reconciling the results with calculations based on independently-sourced data.

Using the settlement software, the Company would be able to query and identify the MISO revenues and expenses that can be separately identified by resource or contract. This data can then be incorporated into the accounting system to facilitate the Pseudo Separation. Exhibit___(KLE-1), Schedule 5 identifies the methodology that can be used to allocate MISO charge types to the appropriate jurisdiction.

Q. PLEASE EXPLAIN HOW GENERATION RESOURCES ARE REGISTERED WITH MISO, AND HOW THIS RELATES TO THE ALLOCATION PROCESS.

A. In order to function, MISO has information about the location, capacity, and ownership of each generation resource. This information is collectively referred to as "registration" with MISO. Some of the NSP System's generation resources have a one-to-one relationship between the settlement location and the resource; these are called "non-aggregated" resource registrations. Others have a one-to-many relationship between the settlement location and the resource; these are called "aggregated" resource registrations. For example, ten separate generation resources are grouped in the Chanarambie settlement location.

For non-aggregated resource registrations, resource-specific revenue and cost related to sales of energy into the MISO market will be assigned to the specific jurisdiction(s) paying for the energy resource. The MISO settlement statements and the settlement software already include all necessary data required to

identify resource-specific revenues and costs for non-aggregated resource registrations.

For aggregated registrations, resource-specific revenue and cost related to sales of energy into the MISO market will also be assigned to the specific jurisdiction(s) paying for the energy resource. Because the MISO settlement statements and the settlement software cannot isolate resource-specific revenues and costs for aggregated registrations, individual resource revenues and costs will be determined on a prorated basis based on the resource's nameplate capacity in relation to the total aggregated registration point's nameplate capacity. This is the process currently used to remit payment for energy purchases to the vendors that comprise the same settlement location.

Q. WHAT ASSUMPTIONS HAS THE COMPANY MADE ABOUT MISO LOAD AND RESERVE ZONES?

A. The NSP service territory is divided into "load zones," which are approved and maintained by MISO to facilitate energy transactions at aggregated load levels. Each load zone is associated with a load node. "Reserve zones" are divisions of the MISO service territory containing a specific group of resource and load nodes; each reserve zone is used for the purpose of establishing reserve requirements and pricing for the ancillary services market discussed below.

At this point, the Company proposes for simplicity that all MISO load costs or purchases of energy from the MISO market be shared across the system using current cost-sharing methods. Currently, a portion of the North Dakota load, serving Minot, is behind the NSP.NSP load node, and a portion of the Minnesota load settles at the OTP.NSP load node. Should it be determined

that MISO load costs specific to the North Dakota jurisdiction be direct-assigned to North Dakota customers (i.e. setting up a specific North Dakota load node), the Company would be able to do that with modifications to the MISO commercial and/or network models.

Q. WHAT IS BEHIND THE METER GENERATION?

A. Behind the Meter Generation (BTMG) refers to generation resources used to serve wholesale or retail load located behind a commercial pricing node; for example, a solar garden that generates power on the utility's distribution system. This power may be used either as a reduction to load or as an accredited capacity resource. BTMG benefits all jurisdictions by reducing the amount of load settled through the MISO market or by providing accredited capacity. Accordingly, the benefits of BTMG should be removed from the specific jurisdiction(s) not paying for the resource.

Q. HOW WILL BTMG BE ALLOCATED IN THE PSEUDO SEPARATION STRUCTURE?

A. The dollar benefit of BTMG to be removed from a specific jurisdiction will be calculated by taking the hourly metered generation volume of the energy resource, multiplied by the hourly LMP of the NSP.NSP node, and then multiplied by the jurisdiction's load percentage. BTMG that is used as a capacity resource will be assigned to the specific jurisdiction paying for the resource.

Q. WHAT IS A FINANCIAL TRANSMISSION RIGHT (FTR)?

A. An FTR is a financial instrument that entitles the holder to receive compensation for transmission congestion charges that arise when the transmission grid is congested and generation must be dispatched out of order

to relieve the congestion. FTRs are intended to protect utilities from increased costs due to transmission congestion. They do not represent a right for physical delivery of power.

Q. HOW WILL FTRS BE ALLOCATED IN THE PSEUDO SEPARATION STRUCTURE?

A. No changes would be made to the current cost-sharing methods for FTRs. FTR costs and revenues need to be shared with all jurisdictions due to the unified design of the FTR congestion hedging strategy.

Q. WHAT IS AN AUCTION REVENUE RIGHT (ARR)?

A. An ARR entitles a market participant to a share of the revenue generated in the Annual FTR Auction. ARRs are allocated by MISO to market participants based on firm historical usage of the MISO transmission system.

Q. HOW WILL ARRS BE ALLOCATED IN THE PSEUDO SEPARATION STRUCTURE?

A. It is Xcel Energy's policy to convert all ARRs to FTRs to hedge against congestion charges; thus, there are no ARRs to allocate in the Pseudo Separation structure.

Q. WHAT IS THE ANCILLARY SERVICES MARKET?

A. In order for the transmission network to function properly and reliably, there must be a certain baseline amount and balance of power flowing through it. To regulate this, MISO provides services that are collectively known as the Ancillary Services Market (ASM). There are three primary services provided through the ASM: regulation of reserves, spinning reserves, and supplemental reserves. Regulation reserves, in this context, refer to reserves that allow the operator of the system to physically balance supply and demand on a real-time

basis. Spinning reserves provide energy to meet demand in the event of an unexpected loss of generation or transmission resource; in essence, spinning reserves are stand-by emergency power that is being provided even though not currently needed. Supplemental reserve is similar to spinning reserve, but from resources that are not necessary online and providing power. MISO prices and compensates power generators for providing these services.

Q. HOW WOULD ASM COSTS AND REVENUES BE ALLOCATED UNDER PSEUDO SEPARATION?

A. ASM revenues would be separately tracked by generating resource and would be assigned to the specific jurisdiction(s) paying for the energy resource. Purchases of ASM from the MISO market are identified by reserve zone and would be allocated to each jurisdiction based on current cost-sharing methods.

d. Trade Margins

Q. WHAT ARE TRADE MARGINS?

A. There are two types of trade margins: Asset Based margins and Non-Asset Based margins. Asset Based margins are derived from short-term sales of "excess" generation (e.g. system resources not needed to serve retail and wholesale native load). Non-Asset Based margins stem from purchases and sales that we execute solely for the purpose of generating margins and do not rely on generation resources used to meet retail load. Currently the Company shares 100 percent of the Asset Based margins with North Dakota ratepayers and 50 percent of the Non-Asset Based margins with North Dakota ratepayers.

Q. HOW WOULD TRADE MARGINS BE ALLOCATED UNDER PSEUDO SEPARATION?

A. With respect to Non-Asset Based margins, under a Pseudo Separation scenario, no changes are anticipated to the current process of allocating these margins to jurisdictions. For Asset Based margins, only the specific jurisdiction(s) paying for the generation resource would benefit from any generation margins arising from excess sales related to the generation resource. Currently, the excess energy sold into the market is assigned the highest energy cost by hour. A sales summary by generator report would be produced from Cost Calculator—an internal proprietary costing software—for each initial settlement and resettlement period to identify total costs and excess sales by generating resource. From this, the generation margin benefit can be determined.

e. Renewable Energy Credits

Q. WHAT ARE RENEWABLE ENERGY CREDITS (RECS) AND HOW ARE THEY CURRENTLY ACCOUNTED FOR?

A. RECs are marketable environmental instruments that represent proof that energy was generated from eligible renewable energy sources. RECs are awarded upon delivery of the associated energy and can be bought and sold. NSPM acquires RECs from the generation or purchase of renewable power. Currently, all RECs produced by qualified renewable energy sources are registered in the Midwest Renewable Energy Tracking System (M-RETS) database and are allocated to specific accounts by jurisdiction.

Q. HOW WOULD RECS BE ALLOCATED UNDER THE PSEUDO SEPARATION STRUCTURE?

A. Only the specific jurisdiction(s) paying for the qualified renewable generation resources would receive an allocation of the RECs. Any sale of RECs would be from the jurisdictional portfolio and would be direct-assigned to the

jurisdiction from which the sale is made. This is the same as the Company's current process.

2. Revenue Requirement Items

a. Costs and Revenues Associated with Generation Facilities

Q. PLEASE DESCRIBE HOW THE COSTS AND REVENUES THAT COMPRISE THE REVENUE REQUIREMENTS ARE GENERALLY ACCOUNTED FOR NOW.

A. As the Commission is aware, we use an allocation system to assign costs and revenues for generation facilities to the jurisdictions for ratemaking purposes. Costs and revenues are generally allocated using the 12CP Method or energy, all as set forth in detail in the Cost Assignment and Allocation Manual (CAAM). Attached as Exhibit___(KLE-1), Schedule 6 is the Company's response to Commission Data Request No. 2-13, which describes the CAAM and explains that it is on file with the Commission.

Q. WHAT COSTS AND REVENUES CAN CONTINUE TO BE DIRECT-ASSIGNED ONCE PSEUDO SEPARATION IS IMPLEMENTED?

A. There are many costs and revenues that can be directly identified by the specific generation resource. Items that can be directly identified by the specific generation resource include plant in service, accumulated depreciation, accumulated deferred income tax and associated plant tax records, depreciation expense, production tax credits, and fuel inventory. As to all of these categories, cost and revenues related to the Legacy System will be shared across the system using current cost-sharing methods. Cost and revenues from new resource additions will be separately identified and assigned to the specific jurisdiction(s) paying for the resource.

b. Capacity Expense and Capacity Sales

Q. HOW WILL CAPACITY EXPENSE BE ALLOCATED IN PSEUDO SEPARATION?

A. With respect to capacity expense, to the extent that capacity is purchased through a PPA or other contractual arrangement that has separate and distinct capacity pricing, those costs and benefits would be assigned to the specific jurisdiction(s) much like plant related costs. With respect to capacity sales, such as through the MISO capacity markets or bilateral contracts, capacity sales from the Legacy System will be shared across the system using current cost-sharing methods. To the extent that capacity sales are from new resource additions, we would expect to assign the revenues from those sales to the specific jurisdiction(s) paying for the resource.

c. Property Insurance Expense

Q. HOW WILL PROPERTY INSURANCE BE ALLOCATED IN PSEUDO SEPARATION?

A. Property insurance will be allocated to a specific generation resource based on insurable values. Insurance costs will be separately identified and assigned to the specific jurisdiction(s) paying for the energy resource.

d. Property Tax Expense

Q. HOW WILL PROPERTY TAX EXPENSE BE ALLOCATED IN PSEUDO SEPARATION?

A. Tax statements are received by individual generation resource in Minnesota, North Dakota, and South Dakota; thus the costs will be separately identified and assigned to the specific jurisdiction(s) paying for the energy resource.

e. O&M Expense

Q. HOW WILL O&M EXPENSE BE ALLOCATED IN PSEUDO SEPARATION?

A. O&M expense for the production business area, which includes fuel handling expense, is generally identifiable by generating resource. To the extent that O&M expense can be directly identified by generating resource, the costs will be assigned to the specific jurisdiction(s) paying for the energy resource. There are certain O&M expenses for the production business area that are not identifiable by generating resource. For example, certain management oversight costs and IT costs are tracked at the Energy Supply business area and not at the specific generating resource. These costs would be allocated to each jurisdiction based on current cost-sharing methods.

f. Miscellaneous Revenue

Q. HOW WOULD OTHER MISCELLANEOUS REVENUE, SEPARATE FROM ITEMS ADDRESSED ABOVE, BE ALLOCATED?

A. Other electric revenue, such as revenue from ash handling, is available by generating plant in the general ledger, allowing for the revenues to be assigned to a specific jurisdiction under a Pseudo Separation structure.

3. Regulatory Recovery Mechanisms

Q. WHAT REGULATORY RECOVERY MECHANISMS WOULD BE AFFECTED BY PSEUDO SEPARATION?

A. The Company anticipates that modifications would need to be made to the Fuel Cost Rider and the Interchange Agreement tariff under Pseudo Separation. Both mechanisms currently allocate costs and benefits to the jurisdiction from a system-wide level. Pseudo Separation would require that these mechanisms be restructured into more of a two-step approach. The first step would be a direct assignment of costs and benefits to the jurisdiction relating to specific generation resources. The second step would be an

allocation of costs and benefits that either cannot be directly assigned to a generation resource or those generation resources that continue to be shared across the NSP System.

V. CONCLUSION

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

A. Yes, it does.

Resume of Karen L. Everson

Director of Utility Accounting

Xcel Energy Services Inc.
1414 W. Hamilton Avenue
Eau Claire, WI 54701

Current Responsibilities

Since March 2010, I have worked in the Utility Accounting department as Director of Utility Accounting. As the Director of Utility Accounting, I provide senior financial and technical accounting leadership for the NSPM and NSPW operating utilities. I am responsible for the accounting for energy procurement and trading, cost analysis, clause and rider mechanisms, Interchange Agreement, margin analysis, FERC accounting, and reporting.

Prior Testimony

Minnesota – Electric Rate Case
Docket No. E002/GR-10-971

Wisconsin – Electric and Gas Rate Case
Docket Nos. 05-EI-139, 4220-UR-115, 4220-UR-119

Energy-Related Employment History

Xcel Energy Services Inc. – Eau Claire, WI

- Director of Utility Accounting, 2010 to Present
- Manager of Regulatory Accounting , 2003 – 2010
- Accounting/Financial Consultant, 2000 – 2003

Northern States Power Company Wisconsin – Eau Claire, WI

- Interim Finance Team Leader, 2000
- Senior Accountant, 1996 – 2000
- Accountant, 1994 – 1996

Education

University of Wisconsin – Eau Claire, May 1994
Bachelor of Business Administration, Comprehensive Accounting Major

Estimated Incremental Costs for NSPD Stand-Alone Entity

	Estimated 2020 Base Costs	Estimated 2020 Base Costs with Full Labor Loadings	
Executive Management			
President	245,000	357,292	
Executive Assistant	71,000	103,542	
Bismarck office rent	55,000	55,000	
	371,000	515,833	515,000
Incremental Labor			
Market Operations Accounting	188,000	274,167	
NSP Utility Accounting	87,500	127,604	
Business Area Finance	87,500	127,604	
	363,000	529,375	530,000
Outside Services			
Auditing and Accounting	220,000	220,000	
Benefits	140,000	140,000	
Formula Rate	30,000	30,000	
	390,000	390,000	390,000
Total			1,435,000

Executive Management

Cost estimates are loosely based on those for NSPW.

Incremental Labor

Market Operations Accounting is responsible for the settlement of MISO statements. Two additional FTEs (1 Q level and 1 P level) are expected to handle additional workload for the new legal entity.

NSP Utility Accounting is responsible for the accounting for fuel and purchased power expense, regulatory recovery mechanisms, and certain reporting and analysis. One additional FTE (P level) is expected to handle additional workload for the new legal entity.

Business Area Finance is responsible for providing accounting, reporting, and forecasting support to the business areas. One additional FTE (P level) is expected to handle additional workload for the new legal entity.

Outside Services

Auditing and Accounting services are expected for the audit of SEC and FERC financial statements and other accounting support for the new legal entity.

Fees are expected related to the Benefits accounting for the new legal entity, including actuarial services and claims management.

Legal and other administrative fees are expected for the production formula rate.

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☐ **Public Document – Not Public (Or Privileged) Data Has Been Excised**
☒ **Public Document**

Xcel Energy

Docket No.:	PU-12-813, PU-13-194, PU-13-195, PU-13-706, PU-13-707, PU-13-708, PU-13-742, PU-13-743	Data Request No.	2-12
Response To:	North Dakota Public Service Commission Commission Advocacy Staff		
Requestor:	PA Consulting Group		
Date Received:	May 10, 2017		

Question:

In the Company's response to MN Public Utilities Commission Information Request No. 10 in Docket No. E002/M-16-777, the Company states "The same is generally true for service company allocations. While the costs for some services currently billed to NSPM may shift to a new North Dakota operating company providing cost savings…" Please indicate what specific costs the Company is referring to, how those costs are allocated now between the different state utilities, and how the cost allocation would change under the referenced "shift".

Response:

Like most large utility holding companies, Xcel Energy Inc. utilizes a service company subsidiary, Xcel Energy Services Inc. (XES), to provide common services to its subsidiary companies including utility operating companies such as Northern States Power Company, a Minnesota corporation (NSPM) which provides retail electric service to North Dakota and its affiliated operating companies; Northern States Power Company, a Wisconsin corporation (NSPW); Southwest Public Service Company (SPS); and Public Service Company of Colorado (PSCo). Examples of the corporate services XES provides include managerial, financial, legal, engineering, marketing, auditing, human resources, marketing, tax, communications, network and IT services.

XES bills NSPM for its services under a Service Agreement between XES and NSPM, which is included as Attachment A. Under the Service Agreement, XES costs that can be directly identified as pertaining to a specific operating company are direct assigned to that operating company. Other costs are allocated to the various

operating companies when a service company cost supports more than 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. Allocation factors include the numbers of employees, amounts of assets, and amounts of revenues in each affiliate.

Should a new operating company be established to provide electric service to our North Dakota customers, a new Service Agreement between the new operating company and XES would direct assign costs incurred on behalf of the new operating company and also allocate to the new operating company common costs consistent with the allocation ratios established in the Service Agreement. It is first necessary to establish how the new operating company will be structured, how it will be staffed, what assets it will own, and other items so that it can be possible to fully calculate the "cost shifts" that would result. To provide context for the impacts of the potential changes in XES costs, our RTF Application provided a high level estimate of the impact of possible changes to service company costs. These estimates will be further refined should the outcome of this proceeding result in Xcel Energy establishing a separate operating company to serve its North Dakota customers.

Preparer: Joanna Yugo
Title: Principal Rate Analyst
Department: Revenue Analysis
Telephone: 612-215-4633
Date: May 24, 2017

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]

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 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 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.

Attributes for NSPD Stand-Alone Entity
For Purposes of Developing Service Company Allocations
For Estimate Purposes Only

Attribute	Item	Estimated NSPD Stand-Alone
Amounts in thousands (attributes 1-4)		
1	Electric Distribution Plant	$180,251
	Electric General Plant	9,556
	Common General Plant (Direct + Allocation)	22,684
	Common Intangible Plant (Direct + Allocation)	18,946
	Electric Intangible Plant	35
	Gross Plant	$231,472
2	Electric Distribution Plant	$113,165
	Electric General Plant	6,218
	Common General Plant (Direct + Allocation)	16,939
	Common Intangible Plant (Direct + Allocation)	6,451
	Electric Intangible Plant	28
	Net Plant	$142,801
3	Utility Plant (incl. CWIP)	$151,000
	Other Property and Investments	-
	Current and Accrued Assets	38,000
	Deferred Debits	61,000
	Total Assets	$250,000
4	Residential	$77,876
	Commercial & Industrial	124,435
	Public Street & Highway Lighting	1,595
	Other Sales to Public Authority	1,352
	Other Electric Revenues	1,089
	Total Electric Revenues	$206,347
5	Customer Count	93,768
6	Number of Employees	83
7	Number of Computers	130
8	Mwh Generation	-

Indirect Allocations for NSPD Stand-Alone Entity
For Purposes of Developing Service Company Allocations
For Estimate Purposes Only

ID	Method	NSPM (Total, Prior to Separation for NSPD Stand-Alone)	Estimated NSPD Stand-Alone	
1	AP Transactions - 1	34.6%	0.0%	*Note 1*
2	Assets/Revenue/No. of Employees - 1	45.2%	1.1%	
3	Assets/Revenue/No. of Employees - 2	45.3%	1.1%	
4	Assets/Revenue/No. of Employees - 3	45.3%	1.1%	
5	Assets/Revenue/No. of Employees - 3A	45.3%	1.1%	
6	Assets/Revenue/No. of Employees - 3B	45.3%	1.1%	
7	Assets/Revenue/No. of Employees - 4	52.9%	1.3%	
8	Assets/Revenue/No. of Employees - 4A	52.9%	1.3%	
9	Assets/Revenue/No. of Employees - 5	0.0%	0.0%	
10	Assets/Revenue/No. of Employees - 5A	0.0%	0.0%	
11	Assets/Revenue/No. of Employees - 6	86.8%	2.1%	
12	Assets/Revenue/No. of Employees (Corp Gov) - 1	40.4%	1.0%	
13	Assets/Revenue/No. of Employees (Corp Gov) - 1A	40.4%	1.0%	
14	Assets/Revenue/No. of Employees (Corp Gov) - 2	40.5%	1.0%	
15	Assets/Revenue/No. of Employees (Corp Gov) - 3	40.5%	1.0%	
16	Assets/Revenue/No. of Employees (Corp Gov) - 3A	40.5%	1.0%	
17	Average of a Select Set of Software Allocators - 1	38.3%	0.5%	
18	Average of a Select Set of Software Allocators - 2	28.0%	0.3%	
19	Average of All Software Percentages - 1	37.4%	0.6%	
20	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. - 1	35.0%	0.0%	
21	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. - 1A	37.0%	0.0%	
22	Electric Distribution Plant - 1	36.5%	1.7%	
23	Electric Distribution Plant - 1A	36.5%	1.7%	
24	Electric Distribution Plant - 1B	36.5%	1.7%	
25	Electric Distribution Plant/ Gas Distribution Plant - 1	32.6%	0.8%	
26	Electric Distribution Plant/ Gas Distribution Plant - 2	38.2%	1.1%	
27	Electric Distribution Plant/ Gas Transmission Plant/ Gas Distribution Plant - 1	32.8%	1.2%	
28	Electric Production Plant/ Electric Transmission Plant/ Electric Distribution Plant - 1	42.0%	0.6%	
29	Electric Production Plant/ Electric Transmission Plant/ Electric Distribution Plant/ Gas Transmission Plant/ Gas Distribution Plant - 1	41.6%	0.4%	
30	Electric Production Plant/ Electric Transmission Plant/ Electric Distribution Plant/ Gas Transmission Plant/ Gas Distribution Plant - 2	86.4%	0.9%	
31	Electric Production Plant/ Electric Transmission Plant/ Electric Distribution Plant/ Gas Transmission Plant/ Gas Distribution Plant - 3	0.0%	0.0%	
32	Electric Transmission Plant - 1	37.5%	0.0%	
33	Electric Transmission Plant - 1A	37.5%	0.0%	
34	Electric Transmission Plant - 1B	37.5%	0.0%	
35	Electric Transmission Plant - 2	76.6%	0.0%	
36	Electric Transmission Plant/ Electric Distribution Plant/ Gas Transmission Plant/Gas Distribution Plant - 1	34.6%	0.7%	
37	Gas Distribution Plant - 1	28.7%	0.0%	
38	Gas Distribution Plant - 1A	28.7%	0.0%	
39	Gas Distribution Plant - 1B	28.7%	0.0%	
40	Gas Transmission Plant - 1	8.5%	0.0%	
41	Gas Transmission Plant/ Gas Distribution Plant - 1	18.6%	0.0%	
42	Invoice Transactions - 1	33.1%	0.0%	*Note 1*
43	Joint Operating Agreement - 1	40.9%	0.0%	
44	Joint Operating Agreement - 1A	40.9%	0.0%	
45	Labor Dollars - 1	42.4%	0.0%	*Note 1*
46	MWH Generation - 1	35.6%	0.0%	
47	MWH Generation - 1A	35.6%	0.0%	
48	MWH Generation - 1B	35.6%	0.0%	
49	MWH Generation - 1C	35.6%	0.0%	
50	MWH Generation - 2	0.0%	0.0%	
51	MWH Generation - 2A	0.0%	0.0%	
52	MWH Generation - 2B	0.0%	0.0%	
53	MWH Generation - 3	93.9%	0.0%	
54	MWH Generation - 3A	93.9%	0.0%	
55	MWH Generation - 3B	93.9%	0.0%	
56	MWH Hours Sold - 1	37.2%	0.0%	
57	No. of Business Objects Users - 1	41.2%	0.0%	*Note 1*
58	No. of Computers - 1	54.3%	1.2%	
59	No. of Computers/ No. of Customers/ No. of Employees - 1	46.0%	1.3%	
60	No. of Contacts - 1	34.9%	0.0%	*Note 1*
61	No. of Customer Bills - 1	39.7%	0.0%	*Note 1*
62	No. of Customers - 1	35.4%	1.7%	
63	No. of Customers - 2	35.5%	1.7%	
64	No. of Customers - 2A	35.5%	1.7%	
65	No. of Customers - 2B	35.5%	1.7%	
66	No. of Customers - 3	0.0%	0.0%	
67	No. of Customers - 4	84.2%	4.0%	
68	No. of Customers/ No. of Contacts - 1	35.2%	0.8%	
69	No. of Employees - 1	48.1%	1.0%	
70	No. of Employees - 2	48.2%	1.0%	
71	No. of Gas Customers - 1	0.0%	0.0%	
72	No. of Maximo Users - 1	33.9%	0.0%	
73	No. of Meters - 1	35.8%	0.0%	*Note 1*
74	No. of Meters/ No. of Contacts - 1	35.3%	0.0%	*Note 1*
75	No. of Residential Customers - 1	39.3%	1.0%	
76	Phones/ Radios/ Computers - 1	47.4%	0.4%	
77	Purchasing Transactions - 1	27.8%	0.0%	*Note 1*
78	Revenue - 1	41.5%	1.7%	
79	Total AP/ Inventory/ Work Management Purchase Transactions - 1	34.6%	0.0%	*Note 1*
80	Total Plant - 1	44.8%	0.5%	
81	Work Management Transactions - 1	50.4%	0.0%	*Note 1*

Note 1 - Allocation based on a statistic not calculated for a separate NSPD. Estimated allocation included in analysis.

Indirect Allocations for NSPD Stand-Alone Entity
For Purposes of Developing Service Company Allocations
For Estimate Purposes Only

Amounts in thousands

NSPM Service Company Allocations in 2016 *(Note 1)*	228,973	
Estimated Escalation to 2020	8.6%	
Estimated NSPM Service Company Allocations in 2020	248,665	
Estimated Allocation to NSPM Electric Utility in 2020	229,382	92.2%
Estimated Allocation to North Dakota Electric in 2020	14,435	6.3%
Estimated Service Company Allocations in 2016 to NSPD Stand-Alone	5,135	
Estimated Escalation to 2020	8.6%	
Estimated Service Company Allocations in 2020 to NSPD Stand-Alone	5,577	
Difference between Service Company Allocations in 2020 to NSPD Stand-Alone and Estimated Allocation to North Dakota Electric in 2020	8,858	

Note 1: Immaterial difference from actual 2016 Service Company Allocations of $231,132

Allocation Method by MISO Charge Type under Pseudo Separation

Row	Description	Market Charge Type Code	Allocation Method under Pseudo Separation
Day-Ahead Charge Types			
1	Day-Ahead Asset Energy Amount	DA_ASSET_EN	Energy Sales will be identified by resource and assigned to the specific jurisdiction(s) paying for the energy resource. Energy Purchases related to load will be allocated to each jurisdiction based on current cost-sharing methods.
2	Day-Ahead Financial Bilateral Transaction Congestion Amount	DA_FIN_CG	Non-Asset Bilateral Transactions will be identified by contract and assigned to the specific jurisdiction(s) paying for the energy resource.
3	Day-Ahead Financial Bilateral Transaction Loss Amount	DA_FIN_LS	Non-Asset Bilateral Transactions will be identified by contract and assigned to the specific jurisdiction(s) paying for the energy resource.
4	Day-Ahead Market Administration Amount	DA_ADMIN	Schedule 17 administrative costs will be identified by resource, contract and load. Resource and contract cost will be assigned to the specific jurisdiction(s) paying for the energy resource. Charges related to load will be allocated to each jurisdiction based on current cost-sharing methods.
5	Day-Ahead Schedule 24 Allocation Amount	DA_SCHD_24_ALC	Schedule 24 administrative costs will be identified by resource, contract and load. Resource and contract cost will be assigned to the specific jurisdiction(s) paying for the energy resource. Charges related to load will be allocated to each jurisdiction based on current cost-sharing methods.
6	Day-Ahead Non-Asset Energy Amount	DA_NASSET_EN	Non-Asset Bilateral Transactions will be identified by contract and assigned to the specific jurisdiction(s) paying for the energy resource.
7	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	RBT_CG	Non-Asset Bilateral Transactions will be identified by contract and assigned to the specific jurisdiction(s) paying for the energy resource.
8	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	DA_GFACO_RBT_LS	Non-Asset Bilateral Transactions will be identified by contract and assigned to the specific jurisdiction(s) paying for the energy resource.

Allocation Method by MISO Charge Type under Pseudo Separation

Row	Description	Market Charge Type Code	Allocation Method under Pseudo Separation
9	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	DA_GFAOB_RBT_CG	Non-Asset Bilateral Transactions will be identified by contract and assigned to the specific jurisdiction(s) paying for the energy resource.
10	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	DA_GFAOB_RBT_LS	Non-Asset Bilateral Transactions will be identified by contract and assigned to the specific jurisdiction(s) paying for the energy resource.
11	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	DA_RSG_DIST	Day-Ahead Revenue Sufficiency Guarantee costs are based on locational energy withdrawals. Resources and contract cost will be assigned to the specific jurisdiction(s) paying for the energy resource. Load cost will be allocated to each jurisdiction based on current cost-sharing methods.
12	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	DA_RSG_MWP	Energy Sale related revenue will be identified by resource and assigned to the specific jurisdiction(s) paying for the energy resource.
13	Day-Ahead Virtual Energy Amount	DA_VIRT_EN	Virtual based hedging strategies will be allocated to each jurisdiction based on current cost-sharing methods.
Real-Time Charge Types			
14	Real-Time Asset Energy Amount	RT_ASSET_EN	Energy Purchases related to load will be allocated to each jurisdiction based on current cost-sharing methods.
15	Non-Excessive Energy Amount	RT_ASM_NXE	Energy Sales will be identified by resource and assigned to the specific jurisdiction(s) paying for the energy resource.
16	Excessive Energy Amount	RT_ASM_EXE	Energy Sales will be identified by resource and assigned to the specific jurisdiction(s) paying for the energy resource.
17	Real-Time Distribution of Losses Amount	RT_LOSS_DIST	Loss distribution is based on NSP's share of MISO load and will be allocated to each jurisdiction based on current cost-sharing methods.
18	Real-Time Financial Bilateral Transaction Congestion Amount	RT_FIN_CG	Non-Asset Bilateral Transactions will be identified by contract and assigned to the specific jurisdiction(s) paying for the energy resource.

Allocation Method by MISO Charge Type under Pseudo Separation

Row	Description	Market Charge Type Code	Allocation Method under Pseudo Separation
19	Real-Time Financial Bilateral Transaction Loss Amount	RT_FIN_LS	Non-Asset Bilateral Transactions will be identified by contract and assigned to the specific jurisdiction(s) paying for the energy resource.
20	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	RT_GFACO_RBT_CG	Non-Asset Bilateral Transactions will be identified by contract and assigned to the specific jurisdiction(s) paying for the energy resource.
21	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	RT_GFACO_RBT_LS	Non-Asset Bilateral Transactions will be identified by contract and assigned to the specific jurisdiction(s) paying for the energy resource.
22	Real-Time Market Administration Amount	RT_ADMIN	Schedule 17 administrative costs will be identified by resource, contract and load. Resource and contract cost will be assigned to the specific jurisdiction(s) paying for the energy resource. Charges related to load will be allocated to each jurisdiction based on current cost-sharing methods.
23	Real-Time Schedule 24 Allocation Amount	RT_SCHD_24_ALC	Schedule 24 administrative costs will be identified by resource, contract and load. Resource and contract cost will be assigned to the specific jurisdiction(s) paying for the energy resource. Charges related to load will be allocated to each jurisdiction based on current cost-sharing methods.
24	Real-Time Schedule 24 Distribution Amount	RT_SCHD_24_DIST	Schedule 24 revenue is a credit to NSP as a reimbursement for Operational Expenses due to our functions in the MISO Energy and Operating Reserve Market. Schedule 24 allocations will not change.
25	Real-Time Miscellaneous Amount	RT_MISC	Miscellaneous MISO settlement cost and revenues will be allocated to each jurisdiction based on current cost-sharing methods.
26	Real-Time Net Inadvertent Distribution	RT_NI_DIST	Net Inadvertent uplift costs are based on total portfolio activity and will be allocated to each jurisdiction based on current cost-sharing methods.

Allocation Method by MISO Charge Type under Pseudo Separation

Row	Description	Market Charge Type Code	Allocation Method under Pseudo Separation
27	Real-Time Non-Asset Energy Amount	RT_NASSET_EN	Non-Asset Bilateral Transactions will be identified by contract and assigned to the specific jurisdiction(s) paying for the energy resource.
28	Real-Time Revenue Neutrality Uplift Amount	RT_RNU	Revenue Neutrality Uplift costs are based on NSP's total share of MISO load and will be allocated to each jurisdiction based on current cost-sharing methods.
29	Real-Time Revenue Sufficiency Guarantee 1st Pass Distribution Amount	RT_RSG_DIST1	Real-Time Revenue Sufficiency Guarantee Costs are based on the sum of total portfolio deviations and will be allocated to each jurisdiction based on current cost-sharing methods.
30	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	RT_RSG_MWP	Energy Sale related revenue will be identified by resource and assigned to the specific jurisdiction(s) paying for the energy resource.
31	Real-Time Virtual Energy Amount	RT_VIRT_EN	Virtual based hedging strategies will be allocated to each jurisdiction based on current cost-sharing methods.
32	Real-Time Price Volatility Make Whole Payment	RT_PV_MWP	Energy Sale related revenue will be identified by resource and assigned to the specific jurisdiction(s) paying for the energy resource.
33	Real-Time Demand Response Uplift	RT_DRR_UPL	Demand Response charges will be allocated to each jurisdiction based on current cost-sharing methods.
34	Real-Time Resource Adequacy Auction Amount	RT_RAA	Capacity Auction revenue and cost will be shared across the system as a reduction to base rates.
35	Real Time MVP Distribution Amount	RT_MVP_DIST	Credits for MISO held MVP ARRs are recorded as a reduction to expense for MISO Schedule 26-A, Multi-Value Project Usage Rate. Amounts are refunded to customers through the TCR rider by virtue of net actual Schedule 26-A expense being recovered through that rider.

Allocation Method by MISO Charge Type under Pseudo Separation

Row	Description	Market Charge Type Code	Allocation Method under Pseudo Separation
Financial Transmission Rights Charge Types			
36	Financial Transmission Rights Hourly Allocation Amount	FTR_HR_ALC	Financial Transmission Rights hedge congestion cost on the whole NSP system and will be allocated to each jurisdiction based on current cost-sharing methods.
37	Financial Transmission Rights Market Administration Amount	FTR_ADMIN	Schedule 16 FTR administrative costs will be allocated to each jurisdiction based on current cost-sharing methods.
38	Financial Transmission Rights Monthly Allocation Amount	FTR_MN_ALC	Financial Transmission Rights hedge congestion cost on the whole NSP system and will be allocated to each jurisdiction based on current cost-sharing methods.
39	Financial Transmission Rights Transaction Amount	FTR_MO_TXN	Financial Transmission Rights hedge congestion cost on the whole NSP system and will be allocated to each jurisdiction based on current cost-sharing methods.
40	Financial Transmission Rights Yearly Allocation Amount	FTR_YR_ALC	Financial Transmission Rights hedge congestion cost on the whole NSP system and will be allocated to each jurisdiction based on current cost-sharing methods.
41	Financial Transmission Rights Full Funding Guarantee Amount	FTR_FFG	Financial Transmission Rights hedge congestion cost on the whole NSP system and will be allocated to each jurisdiction based on current cost-sharing methods.
42	Financial Transmission Rights Guarantee Uplift Amount	FTR_GUL	Financial Transmission Rights hedge congestion cost on the whole NSP system and will be allocated to each jurisdiction based on current cost-sharing methods.
43	Auction Revenue Rights Transaction Amount	FTR_ARR_ARR_TXN	Financial Transmission Rights hedge congestion cost on the whole NSP system and will be allocated to each jurisdiction based on current cost-sharing methods.

Allocation Method by MISO Charge Type under Pseudo Separation

Row	Description	Market Charge Type Code	Allocation Method under Pseudo Separation
44	Financial Transmission Rights Annual Transaction Amount	FTR_ARR_FTR_TXN	Financial Transmission Rights hedge congestion cost on the whole NSP system and will be allocated to each jurisdiction based on current cost-sharing methods.
45	Auction Revenue Rights Infeasible Uplift Amount	FTR_ARR_INF_UPL	Financial Transmission Rights hedge congestion cost on the whole NSP system and will be allocated to each jurisdiction based on current cost-sharing methods.
46	Auction Revenue Rights Stage 2 Distribution Amount	FTR_ARR_STG2_DIST	Financial Transmission Rights hedge congestion cost on the whole NSP system and will be allocated to each jurisdiction based on current cost-sharing methods.
Ancillary Service Charge Types			
47	Day-Ahead Regulation Amount	DA_ASM_REG	Ancillary Sales will be identified by resource and assigned to the specific jurisdiction(s) paying for the energy resource.
48	Day-Ahead Spinning Reserve Amount	DA_ASM_SPIN	Ancillary Sales will be identified by resource and assigned to the specific jurisdiction(s) paying for the energy resource.
49	Day-Ahead Supplemental Reserve Amount	DA_ASM_SUPP	Ancillary Sales will be identified by resource and assigned to the specific jurisdiction(s) paying for the energy resource.
50	Real-Time Regulation Amount	RT_ASM_REG	Ancillary Sales will be identified by resource and assigned to the specific jurisdiction(s) paying for the energy resource.
51	Real-Time Spinning Reserve Amount	RT_ASM_SPIN	Ancillary Sales will be identified by resource and assigned to the specific jurisdiction(s) paying for the energy resource.
52	Real-Time Supplemental Reserve Amount	RT_ASM_SUPP	Ancillary Sales will be identified by resource and assigned to the specific jurisdiction(s) paying for the energy resource.
53	Regulation Cost Distribution Amount	RT_ASM_REG_DIST	Ancillary Procurement Costs are based upon reserve zone requirements and will be allocated to each jurisdiction based on current cost-sharing methods.

Allocation Method by MISO Charge Type under Pseudo Separation

Row	Description	Market Charge Type Code	Allocation Method under Pseudo Separation
54	Spinning Reserve Cost Distribution Amount	RT_ASM_SPIN_DIST	Ancillary Procurement Costs are based upon reserve zone requirements and will be allocated to each jurisdiction based on current cost-sharing methods.
55	Supplemental Reserve Cost Distribution Amount	RT_ASM_SUPP_DIST	Ancillary Procurement Costs are based upon reserve zone requirements and will be allocated to each jurisdiction based on current cost-sharing methods.
56	Real-Time Excessive Deficient Energy Deployment Charge Amount	RT_ASM_EXE_DFE_DEP	Ancillary/Energy Sale related charges will be identified by resource and assigned to the specific jurisdiction(s) paying for the energy resource.
57	Net Regulation Adjustment Amount	RT_ASM_NRGA	Ancillary/Energy Sale related charges will be identified by resource and assigned to the specific jurisdiction(s) paying for the energy resource.
58	Contingency Reserve Deployment Failure Charge Amount	RT_ASM_CRDFC	Ancillary Sale related charges will be identified by specific resource and separately tracked by jurisdiction.
59	Day Ahead Ramp Capability Amount	DA_RC_AMT	Ancillary Sales will be identified by resource and assigned to the specific jurisdiction(s) paying for the energy resource.
60	Real Time Ramp Capability Amount	RT_RC_AMT	Ancillary Sales will be identified by resource and assigned to the specific jurisdiction(s) paying for the energy resource.

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☐ **Public Document – Not Public (Or Privileged) Data Has Been Excised**
☒ **Public Document**

Xcel Energy

Docket No.:	PU-12-813, PU-13-194, PU-13-195, PU-13-706, PU-13-707, PU-13-708, PU-13-742, PU-13-743	Data Request No.	2-13
Response To:	North Dakota Public Service Commission Commission Advocacy Staff		
Requestor:	PA Consulting Group		
Date Received:	May 10, 2017		

Question:

In the Company's response to MN Public Utilities Commission Information Request No. 10 in Docket No. E002/M-16-777, the Company states "We anticipate that Legal Separation will result in a shift of some corporate cost allocations from NSPM and NSPW to the new entity." Please indicate what specific corporate costs the Company is referring to, how those costs are allocated now between the different state utilities, and how the cost allocation would change under the referenced "shift".

Response:

Please see our response to NDPSC DR No. 2-12 regarding the allocation of corporate costs from Xcel Energy Services Inc. (XES). In addition to XES corporate services, other common corporate service (and certain other common) costs are allocated to the various Xcel Energy Inc. operating companies, including NSPM, through a Cost Assignment and Allocation Manual (CAAM) which identifies the methodologies used to ensure expenditures are appropriately and consistently assigned or allocated among utilities and jurisdictions. The CAAM is filed in the Company's rate cases. A copy of the CAAM was last filed with the Commission in the Company's most recent North Dakota rate case (PU-12-813) as Schedule 12 to the Direct Testimony of Company Witness Ms. Anne Heuer.

As discussed in more detail in our response to Data Request No. 2-12, more specific cost impacts and proposed cost allocation methods are dependent on various different variables which will need to be addressed should the Company move forward with a legal separation as part of our RTF.

Preparer: Joanna Yugo
Title: Principal Rate Analyst
Department: Revenue Analysis
Telephone: 612-215-4633
Date: May 24, 2017

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

Northern States Power Company 2013 Electric Rate Increase Application	**Case No. PU-12-813**
Northern States Power Company Advanced Determination of Prudence – Courtenay Wind Application	**Case No. PU-13-706**
Northern States Power Company Advanced Determination of Prudence – Odell Wind Application	**Case No. PU-13-707**
Northern States Power Company Advanced Determination of Prudence – Pleasant Valley Application	**Case No. PU-13-708**
Northern States Power Company Advanced Determination of Prudence – Border Winds Application	**Case No. PU-13-742**
Northern States Power Company 150 MW Border Winds Project – Rolette County, ND Public Convenience & Necessity	**Case No. PU-13-743**
Northern States Power Company Advanced Determination of Prudence – NG Generators Application	**Case No. PU-13-194**
Northern States Power Company Red River Valley NG Unites 1&2 – Hankinson, ND Public Convenience &Necessity	**Case No. PU-13-195**

VERIFICATION

STATE OF MINNESOTA)
) **ss.**
COUNTY OF HENNEPIN)

Karen L. Everson, being first duly sworn on oath, deposes and says that she is the Director of Utility Accounting for Xcel Energy Services Inc. on behalf of Applicant Northern States Power Company, a Minnesota corporation, in the above-captioned matter, that the testimony and schedules submitted in the above-captioned matters under her name were prepared under her direction, that she knows the contents thereof, and that the same is true and correct to the best of her knowledge and belief.

Karen L. Everson

Karen L. Everson

Subscribed and sworn to before me this 11th day of July, 2017.

CYNTHIA D. HARRINGTON
Notary Public, State of Minnesota
My Commission Expires
January 31, 2020

Notary Public
My commission expires: 1-31-2020