

Direct Testimony and Schedules
Adam R. Dietenberger

Before the Minnesota Public Utilities Commission
State of Minnesota

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

Docket No. E002/GR-15-826
Exhibit___(ARD-1)

Cost Assignment and Allocation Principles

November 2, 2015

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1 **I. INTRODUCTION**

2

3 Q. PLEASE STATE YOUR NAME AND OCCUPATION.

4 A. My name is Adam R. Dietenberger. I am the Senior Manager of Service
5 Company Accounting and Cash Processes for Xcel Energy Services Inc.

6

7 Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

8 A. I have 11 years of accounting and finance experience. I have been employed
9 by Xcel Energy Services Inc. (XES or the Service Company) since 2008 in
10 various accounting-related positions. In my current position, I am responsible
11 for the general administration of XES, including accounting, billing,
12 allocations, policies and procedures, and service agreements. I am also
13 responsible for the publication of cost assignment and allocation manuals for
14 Xcel Energy Inc.'s (Xcel Energy or XEI) utility operating companies,
15 including Northern States Power Company – Minnesota (NSPM or the
16 Company), and system processes related to cost allocations.
17 Exhibit____(ARD-1), Schedule 1 summarizes my qualifications and experience.

18

19 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

20 A. In my testimony, I:

- 21 • Present the Cost Assignment and Allocation Manual (CAAM),
22 demonstrating how our cost assignment and allocation methodologies
23 and processes ensure that our costs to serve customers are assigned to
24 the appropriate entities.
- 25 • Discuss changes since our last rate case to specific cost assignment and
26 allocation methods included in amendments to the Service Agreement,

1 which governs assignment of XES costs to the utility operating
2 companies.

3
4 Q. DO THE 2016 TEST YEAR COSTS IN THIS CASE REFLECT THE CHANGES IN THE
5 SERVICE AGREEMENT MENTIONED ABOVE?

6 A. Yes. The test year costs in this case reflect changes included in the Second
7 Amendment to the Service Agreement, approved by the Commission in
8 Docket No. E,G002/AI-14-234, and our proposed changes in the Third
9 Amendment, currently pending before the Commission in Docket No.
10 E,G002/AI-15-536. If the Commission's decision regarding the Third
11 Amendment is different than what we proposed, we will make any necessary
12 adjustments to 2016 test year costs in this case.

13
14 Q. HOW IS YOUR TESTIMONY ORGANIZED?

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

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

20
21 Q. DO YOU PROVIDE ANY ADDITIONAL INFORMATION RELATED TO COST
22 ALLOCATIONS?

23 A. Yes. Appendix A provides a list of relevant information requests from the
24 12-961 and 13-868 rate cases that I have already responded to in this case
25 (with new time frames as appropriate to reflect the November 2, 2015 filing
26 date of this case), indicating where the responsive information is included in
27 my testimony or schedules, or if it is provided in Appendix A.

1

2 **II. COST ASSIGNMENT AND ALLOCATION**

3

4 Q. PLEASE SUMMARIZE THIS SECTION OF YOUR TESTIMONY.

5 A. In this section, I discuss the framework of our cost allocation and assignment
6 principles, including the Service Agreement between XES and NSPM, and the
7 NSPM CAAM. I then discuss the services provided by XES to NSPM, and
8 how the cost of those services are either directly assigned or allocated to the
9 Company, highlighting the changes to cost assignment and allocation methods
10 since our last rate case. I explain the allocation methods used, and quantify
11 the adjustment in this case that results from the use of Total Allocated Labor
12 Hours With Overtime in Minnesota instead of the Number of Employees in
13 our General Allocator and certain other allocations. Finally, I discuss how we
14 handle transactions between Xcel Energy operating company Affiliates and
15 NSPM's non-regulated business activities.

16

17 **A. Cost Assignment and Allocation Framework**

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

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

26

27 Q. ARE THERE GUIDING PRINCIPLES RELATED TO THIS PHILOSOPHY THAT ARE

1 APPLIED BY XCEL ENERGY?

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

- 8 1) Tariffed rates shall be used to value tariffed services provided.
- 9 2) Costs shall be directly assigned to either regulated or non-regulated
10 business activities whenever possible.
- 11 3) Costs that cannot be directly assigned are common costs, which shall be
12 grouped into homogeneous cost categories. Each cost category shall be
13 allocated based on direct analysis of the origin of costs whenever
14 possible. If direct analysis is not possible, common costs shall be
15 allocated based upon indirect cost causation.
- 16 4) When neither direct nor indirect measures of cost causation can be
17 found, the cost category shall be allocated based upon a general
18 allocator.

19
20 Using this process ensures that all subsidiaries are charged for their
21 appropriate share of costs. Thus, our efforts to appropriately allocate and
22 assign costs are aligned with our customers' expectations and interests that
23 they pay for only those costs that are part of the services they receive from the
24 Company.

25
26 Q. PLEASE SUMMARIZE THE COMPANY'S APPROACH TO COST ASSIGNMENT AND
27 ALLOCATION USING THESE PRINCIPLES.

1 A. In accordance with the Commission's Order in Docket 1008, the Company
2 strives to direct charge wherever possible. Direct charges occur when a
3 service being rendered is for the benefit of a specific legal entity only.
4 Allocated, or indirect, charges occur when services cannot be directly assigned
5 to a specific legal entity.

6
7 Q. WHAT IS THE BASIS OF THE ALLOCATED CHARGES?

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

14
15 Q. HOW DOES THE COMPANY PUT THESE PRINCIPLES INTO PRACTICE?

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

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

24
25 The CAAM also helps promote a greater understanding of the Company's
26 cost assignment and allocation principles by providing detailed reference
27 information for both XES and NSPM personnel.

1
2 Q. ARE THESE DOCUMENTS SUBJECT TO COMMISSION APPROVAL?

3 A. Yes. In its November 20, 2014 Order in Docket No. E,G002/AI-14-234, the
4 Commission approved the Second Amendment to the Service Agreement, and
5 directed the Company to submit an annual filing for review and approval of
6 any proposed changes to its allocation methods. A copy of the Service
7 Agreement between XES and NSPM, as approved in that docket, is provided
8 as Exhibit____(ARD-1), Schedule 2. On June 1, 2015, the Company submitted
9 its first annual Petition pursuant to the November 20 Order, requesting
10 approval of the Third Amendment to the Service Agreement. *See* Docket No.
11 E,G002/AI-15-536. The Company will update the rate case as necessary to
12 reflect any Commission decisions in that docket.

13
14 Our first CAAM was approved by the Commission as part of our natural gas
15 rate case in Docket No. G002/GR-04-1511. The CAAM included in this case
16 is NSPM's eighth version and is provided as Exhibit____(ARD-1), Schedule 3.
17 However, the cost assignment and allocation principles applied by NSPM are
18 not new and have been applied in the development of the test year cost of
19 service in all of NSPM's rate cases since Docket No. G002/GR-04-1511.

20
21 Q. DOES THE CAAM REFLECT COST ALLOCATION PRINCIPLES THAT HAVE BEEN
22 ADOPTED BY THE COMMISSION?

23 A. Yes. The principles reflected in the CAAM are based on the guiding
24 principles set forth in the Commission's Order in Docket 1008. We have
25 made some refinements to the application of those principles within our cost
26 allocations over the last several years, primarily due to organizational changes
27 and the separation of our transmission and distribution business areas,

1 previously managed as one group, into three distinct business areas:
2 Transmission, Distribution Operations, and Gas Systems. In our June 1, 2015
3 Petition seeking approval of the most recent amendments to the Service
4 Agreement, the Company re-affirmed its commitment to the cost allocation
5 principles established in Docket 1008, and described how its cost allocation
6 procedures implement and adhere to those principles.

7
8 Q. HOW WAS THE CAAM USED IN THIS PROCEEDING?

9 A. The 2016 budgeted costs used by Company witness Ms. Anne E. Heuer to
10 develop the 2016 test year revenue requirement were developed using the
11 principles contained in the current CAAM.

12
13 Q. HAS THE COMPANY PROVIDED A LIST OF, AND DESCRIPTIONS FOR, THE
14 VARIOUS ALLOCATION METHODS USED FOR THE TEST YEAR?

15 A. Yes. A list of the allocation factors used by XES in its general ledger system
16 for each of our operating companies is provided in Exhibit__(ARD-1),
17 Schedule 4. This schedule also includes a description of each method, by
18 workorder, as well as the 2016 test year percentage allocated to NSPM.
19 Exhibit__(ARD-1), Schedule 5 presents a detailed description of the statistics
20 used to calculate the allocation percentages for these methods, as well as the
21 calculation of the NSPM allocation percentages by workorder. The detailed
22 descriptions of the calculation of the allocation ratios can be found in
23 Appendix A of the Service Agreement, included as Schedule 2.

24
25 Q. ARE THESE THE SAME ALLOCATION METHODS THAT ARE APPLIED IN OTHER
26 JURISDICTIONS SERVED BY XEI UTILITY OPERATING COMPANIES?

27 A. Yes, with one exception. With the exception of the General Allocator used

1 for the Minnesota jurisdiction of NSPM, these allocation methods are the
2 same allocation methods that are in effect and approved in NSPM's other
3 operating jurisdictions (North Dakota and South Dakota), and in the
4 operating jurisdictions of the other Xcel Energy operating companies –
5 Northern States Power Company – Wisconsin (NSPW), Public Service
6 Company of Colorado and Southwestern Public Service Company. The
7 General Allocator used for the Minnesota jurisdiction was established in
8 Docket No. E,G002/AI-10-690, and is consistent with the Commission's
9 March 15, 2011 Order in that proceeding. I discuss the impact of using the
10 General Allocator specific to Minnesota in Section C.1 below.

11
12 Q. HAVE THERE BEEN ANY CHANGES IN ALLOCATION METHODS SINCE THE
13 COMMISSION LAST APPROVED THE SERVICE AGREEMENT?

14 A. Yes. As explained in more detail in our Petition in Docket E,G002/AI-15-
15 536, there are two minor changes to the allocation methodology (as set forth
16 in the Service Agreement): the Company has developed a composite
17 Allocation Method for the Personal Account Representative team; and the
18 Company has proposed to remove references to the Labor Dollars Ratio from
19 the Service Agreement's discussion of Claims Services, Supply Chain, and the
20 Rates and Regulation Service Function. Commission approval of these two
21 changes is pending in Docket No. E,G002/AI-15-536. In its August 7, 2015
22 Comments, the Department of Commerce, Division of Energy Resources
23 (Department) recommended approval of most of the requested amendments.
24 The Company filed Reply Comments on August 17, 2015, and the
25 Department filed its response on October 16, 2015.

26
27 Q. DOES THE 2016 TEST YEAR REFLECT THE USE OF THESE MODIFICATIONS IN

1 ALLOCATION METHODS?

2 A. Yes, it does.

3
4 Q. HAS THE COMPANY CALCULATED THE IMPACT OF THESE MODIFICATIONS ON
5 THE 2016 TEST YEAR?

6 A. No. However, information we provided for 2014 and 2015 in Docket No.
7 E,G002/AI-15-536 gives an indication of the potential impact on 2016 costs.
8 The allocation method for the Personal Account Representative team
9 increases costs for Minnesota customers by approximately \$29,000 in 2014
10 and \$48,000 in 2015. We estimated that the change relating to the Labor
11 Dollars Ratio causes an increase in costs for Minnesota customers by
12 approximately \$44,000 in 2014 and \$50,000 in 2015. As noted above, the
13 Company will make any necessary adjustments in this rate case to reflect the
14 Commission's decisions in that docket.

15
16 **B. Xcel Energy Services Company Charges**

17 Q. PLEASE DESCRIBE THE SERVICES PROVIDED BY XES AND HOW THE COSTS OF
18 PROVIDING THESE SERVICES ARE ASSIGNED AND ALLOCATED.

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

- 21 • Operations and maintenance (O&M) costs of providing corporate
22 services to XES affiliates, such as NSPM. These services typically
23 include any managerial, financial, legal, engineering, marketing, auditing,
24 statistical, advertising, publicity, tax, research or any other service,
25 information or data, which is sold or furnished for a charge.
- 26 • O&M costs for preliminary planning related to capital software projects
27 that benefit more than one operating company or other affiliate.

- 1 • Shared facilities O&M costs that are recorded in clearing accounts.
2 These costs may include (depending on the shared facility),
3 administrative property services labor and non-labor costs, utility
4 expenses, maintenance costs for structures and systems, a pro-rated
5 share of property taxes (for owned buildings), and rent and occupancy
6 expenses (for leased buildings).
- 7 • Fleet, and Warehousing and Purchasing O&M costs that are recorded
8 to clearing accounts.

9
10 Q. PLEASE PROVIDE AN OVERVIEW OF THE METHODS XES USES TO ASSIGN AND
11 ALLOCATE COSTS TO THE COMPANY.

12 A. XES direct *assigns* costs when the specific operating company or Affiliate (or
13 the specific department or business area within the operating company or
14 Affiliate) that should be billed can be identified. For example, the XES
15 Controller's organization can charge NSPM for the work that has been
16 performed to prepare a regulatory filing in Minnesota. Another example is
17 XES employees direct charging the costs for the formation of the Transco
18 entities. A workorder system was created to track and direct charge the costs
19 incurred directly to the Transco entities.

20
21 XES *allocates* costs when a service provided by XES employees supports more
22 than one affiliate. A description of the XES allocation methodology for each
23 service is provided in the Allocation Ratios section of Appendix A of the
24 Service Agreement. To allocate shared costs, XES first identifies
25 homogeneous cost pools that have the same cost driver and then selects the
26 allocation method that has the most cost-causative relationship to the cost
27 driver. For example, the Risk Management department negotiates the

1 corporate umbrella insurance policies that benefit every affiliate. Therefore,
2 these costs are allocated proportionally to every operating affiliate.

3
4 Q. WHAT DOES XES DO TO ENSURE THAT XES COSTS ARE RECORDED
5 CORRECTLY?

6 A. XES takes the following steps to ensure its costs are correctly recorded:

- 7 • Makes the policies and procedures regarding the recording of costs
8 available on the Xcel Energy internal web site for access by all Xcel
9 Energy personnel;
- 10 • Provides mandatory training, delivered through a combination of
11 classroom, online/computer-based and individual/one-on-one training;
- 12 • Conducts regular reviews of any allocations by Budgeting and XES
13 Accounting department personnel; and
- 14 • Conducts internal audits of XES policies and procedures and their
15 application.

16
17 The Company also monitors the accuracy of XES billings through formal and
18 informal review processes, including business area reviews with the operating
19 company Presidents.

20
21 Q. DOES XES REPORT ITS CHARGES TO THE XEI OPERATING COMPANIES AND
22 AFFILIATES?

23 A. Yes. XES files a Federal Energy Regulatory Commission (FERC) Form 60
24 report on an annual basis. This report shows XES billings to the XEI
25 operating companies and Affiliates, including a list of approved allocation
26 methods. A copy of the 2014 XES FERC Form 60 is provided as
27 Exhibit____(ARD-1), Schedule 6.

1
2 Q. CAN XCEL ENERGY OPERATING COMPANIES CHARGE COSTS TO XES?

3 A. No. The operating companies can only direct charge costs to other operating
4 companies or Affiliates.
5

6 **C. Allocation Methods and Factors**

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

9 A. There are three allocation methods: the General Allocator; Allocating
10 Workorders; and Utility Allocations. I will discuss each of these allocation
11 methods in this section of my testimony.
12

13 Q. WHAT IS THE BASIS OF THESE ALLOCATION METHODS?

14 A. Each allocation method relies on underlying operating company statistics
15 relevant to the types of charges that need to be allocated to an Xcel Energy
16 operating company, Affiliate, or business area within an operating company.
17

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

20 A. All of the allocation factors are updated annually, and applied starting with
21 April business transactions, based on the prior calendar year's statistics. XES
22 may also update the statistics used in the allocation factors when there is a
23 significant change, such as the addition or deletion of a legal entity or a
24 material change in operations that is going to be reflected in the statistical
25 information for a particular cost allocation driver.
26

27 Q. ARE THE ALLOCATION METHODS CONSISTENT ACROSS ALL XCEL ENERGY

1 OPERATING COMPANIES?

2 A. No. As I mentioned previously, in Docket No. E,G002/AI-10-690, the
3 Commission required that we use Total Allocated Labor Hours With
4 Overtime (*FTE Hours*) instead of *Number of Employees* in allocating costs to the
5 Minnesota jurisdiction. A list of the allocation factors for XES based on FTE
6 Hours is provided in Exhibit____(ARD-1), Schedule 4(a). The primary
7 allocator impacted by this change is the General Allocator, which I discuss
8 below.

9
10 Q. WERE THERE OTHER CHANGES TO THE COMPANY'S COST ALLOCATION
11 METHODOLOGY THAT RESULTED FROM THE PROCEEDING IN DOCKET NO.
12 E,G002/AI-10-690?

13 A. Yes. The Commission required that we also expand our calculations to
14 incorporate the use of four decimal places in the development of the relevant
15 allocators to further improve the accuracy of the allocations. We have
16 calculated the allocators in this case using four decimal places.

17
18 *1. General Allocator*

19 Q. PLEASE DESCRIBE THE GENERAL ALLOCATOR.

20 A. The General Allocator is used to allocate common costs to operating
21 companies or Affiliates. The calculation used in all jurisdictions other than
22 Minnesota is comprised of three equally-weighted factors: assets, revenues and
23 employees. However, as I discussed above, this is one of the allocation
24 methods requiring modification to use FTE Hours instead of Number of
25 Employees.

26
27 Q. PLEASE DISCUSS THE FTE HOURS COMPONENT OF THE GENERAL ALLOCATOR

1 APPLICABLE TO NSPM.

2 A. The FTE Hours component of the three-factor formula that makes up the
3 General Allocator is calculated as a percentage of the total direct and allocated
4 labor hours for NSPM relative to the total direct and allocated labor hours for
5 all the Affiliates receiving allocations through the General Allocator and is
6 averaged together with Total Assets and Total Revenues, the other two
7 allocation factors that make-up the General Allocator. The resulting
8 percentages are presented in Exhibit____(ARD-1), Schedules 5(a) and 5(b).
9 Schedule 5(a) shows the number of direct and allocated labor hours used to
10 calculate the allocation ratios for the 2016 test year.

11
12 Q. IS THE GENERAL ALLOCATOR THE ONLY ALLOCATION METHOD IN WHICH
13 NUMBER OF EMPLOYEES WAS REPLACED WITH FTE HOURS TO ALLOCATE
14 COSTS TO THE MINNESOTA JURISDICTION?

15 A. No. FTE Hours is also included in other allocation methods besides the
16 General Allocator, as noted in Schedule 5(a).

17
18 Q. IF ALLOCATIONS TO THE MINNESOTA JURISDICTION ARE DIFFERENT THAN
19 THEY ARE TO OTHER OPERATING COMPANIES AND NSPM JURISDICTIONS, IS
20 AN ADJUSTMENT TO THIS RATE CASE NECESSARY?

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

26
27 Q. HAVE YOU QUANTIFIED THE 2016 TEST YEAR ADJUSTMENT NECESSARY TO

1 IMPLEMENT THE FTE HOURS INSTEAD OF NUMBER OF EMPLOYEES FACTOR?

2 A. Yes. Schedule 5(b) shows the calculation of the adjustments to the 2016 test
3 year (for NSPM Total Company), applying the difference between the
4 Number of Employees factor and the FTE Hours factor included in
5 Minnesota's General Allocator, as well as the other affected workorder
6 allocators. The 2016 test year FTE Hours adjustment reduces the costs
7 assigned to the Minnesota Electric jurisdiction by \$1,474,671. Ms. Heuer
8 explains the derivation of the FTE Hours adjustment for the Minnesota
9 Electric jurisdiction in her Direct Testimony.

10
11 Q. PLEASE COMPARE THE FTE HOURS ADJUSTMENT FOR THE 2014 TEST YEAR IN
12 THE COMPANY'S LAST RATE CASE AND THE 2016 TEST YEAR IN THIS CASE.

13 A. In our last rate case, the FTE Hours adjustment for the 2014 test year was a
14 reduction of \$973,280 to the cost of service for the Minnesota Electric
15 jurisdiction. The 2016 test year FTE Hours adjustment is a reduction to the
16 cost of service of \$1,474,671.

17
18 Q. WHY IS THE FTE HOURS ADJUSTMENT FOR THE 2016 TEST YEAR GREATER
19 THAN THAT ADJUSTMENT IN THE 2014 TEST YEAR?

20 A. As an indicator of business activity, the calculation of FTE Hours reflects
21 higher or lower levels of labor hours worked to support operational needs.
22 The change in the FTE Hours adjustment from the 2014 test year to the 2016
23 test year results substantially from the fact that the number of NSPM
24 employees increased from 2012 to 2014, while the cumulative number of
25 employees for all of the Company's operating companies fell over the same
26 period. This change results in a greater deviation between the FTE Hours
27 allocation percentage and the Number of Employees allocation percentage in

1 this case, and thus a larger adjustment in the 2016 test year compared to 2014.

2
3 Table 1 provides a comparative summary of the FTE Hours calculation by
4 business area for the 2014 and 2016 test years.

5
6 **Table 1**
7 **FTE Hours by Business Area for the 2014 and 2016 Test Years**
8 **(Based on 2012 and 2014 Actual NSPM Total Company Results)**

	2014 Test Year (2012 Actuals)		2016 Test Year (2014 Actuals)		
	Overtime Hours	Regular Hours	Overtime Hours	Regular Hours	Net Change in Hours
Business Area					
Chief Executive Officer	-	63	-	124	61
Corporate Services	10,781	394,128	3	26,886	(378,020)
Distribution Operations	225,212	1,943,761	289,138	1,966,747	86,912
Energy Supply	286,440	1,842,681	316,953	1,813,137	969
Financial Operations	331	121,026	102	101,174	(20,081)
Gas Systems	17,267	251,047	16,807	238,053	(13,454)
General Counsel	20	38,623	86	38,801	244
Nuclear Generation	423,620	2,483,875	394,692	2,731,238	218,435
Operations Services	16,328	356,483	31,300	567,972	226,461
Public Policy/Ext. Affairs	-	14,597	-	-	(14,597)
Revenue Group	545	346,952	-	-	(347,497)
Transmission	179,311	895,498	199,087	949,437	73,716
Utilities & Corporate Services	-	-	9,563	531,878	541,441
Direct Hours	1,159,855	8,688,735	1,257,731	8,965,447	374,589
Indirect Hours	12,196	857,270	21,933	882,348	34,815
Total Hours	1,172,051	9,546,005	1,279,664	9,847,795	409,404

22 *Amounts may not total due to rounding.

23
24 Table 1 shows large increases in labor hours in the Nuclear Generation and
25 Operations Services business areas, and a large decrease in the Revenue
26 Group. The increase in FTE Hours for Nuclear Generation is related to an
27 increased number of employees. As discussed in the Direct Testimony of

1 Company witness Mr. Timothy J. O'Connor, this increase is primarily driven
2 by additional employees hired to meet regulatory and safety requirements and
3 the initiative in the Nuclear Generation area to drive performance excellence.
4 The increase in FTE Hours for Operations Services is primarily related to
5 internal business reorganizations that have taken place since 2012. A portion
6 of the hours previously included in the Corporate Services business area are
7 currently included in Operations Services. Additionally, the hours related to
8 the supply chain function supporting the Nuclear Generation business area are
9 now included in the Operations Services business area.

10
11 Table 1 also shows variances that are due to internal business reorganizations
12 that have taken place since 2012. The hours previously included under the
13 Corporate Services, Public Policy and External Affairs and Revenue Group
14 business areas are now included in the following business areas: Operations
15 Services, General Counsel and Utilities and Corporate Services. These
16 changes are the result of internal reorganizations and are largely offsetting.

17
18 As shown in Table 1, there is an overall increase in total FTE Hours in 2016
19 compared to 2014.

20
21 Q. HOW DOES THE INCREASE IN TOTAL FTE HOURS IN 2016 COMPARED TO 2014
22 RESULT IN A GREATER REDUCTION TO THE COST OF SERVICE FOR THE 2016
23 TEST YEAR COMPARED TO 2014?

24 A. To understand how this *increase* in total FTE hours is consistent with a greater
25 FTE Hours *reduction* to the cost of service, it is necessary to consider how the
26 FTE Labor Hours allocation percentage has changed as compared to the
27 Number of Employees allocation percentage. Table 2 below provides a

comparative summary of the allocation percentages for the 2014 and 2016 test years.

Table 2
Allocation Percentage Comparison for the 2014 and 2016 Test Years
(Based on 2014 and 2016 Actual Results)

	2014 Test Year (2012 Actuals)			2016 Test Year (2014 Actuals)		
	NSPM	All OpCos	NSPM Percentage	NSPM	All OpCos	NSPM Percentage
FTE Labor Hours	10,718,054	22,152,172	48.3838%	11,127,459	22,940,934	48.5048%
Number of Employees	4,567	9,194	49.6737%	4,661	9,259	50.3402%
Variance			(1.2899%)			(1.8354%)

The greater deviation between the Number of Employees and FTE Labor Hours allocation percentages in 2016 compared to 2014 is largely due to an increase in the number of NSPM employees compared to the other operating companies. Specifically, the number of NSPM employees increased by 94, while the number of employees increased by only 65 in total for all other operating companies. The increase in total number of employees at NSPM relates to increased needs in the Nuclear Generation area, which I have previously discussed.

The increased number of employees at NSPM compared to the other operating companies means that the Number of Employees allocation percentage has increased. At the same time, the FTE Hours allocation percentage has stayed constant. As a result, the difference between the two allocation percentages increased by 0.5455 percent from the 2014 test year to the 2016 test year. This increase is responsible for approximately \$395,000 –

1 nearly all – of the increase in the FTE Hours adjustment to test year costs in
2 2016 compared to 2014.

3
4 Q. DO YOU EXPECT CHANGES IN FTE HOURS IN THE FUTURE?

5 A. Yes. We continue to expect changes in FTE Hours each year based on
6 operational needs and specific events in a given year. Overtime hours can
7 change significantly from year to year based on the timing of major overhauls
8 and/or outages at the generating plants, as well as overtime related to major
9 storm events.

10
11 2. *Allocating Workorders*

12 Q. WHAT IS THE PURPOSE OF ALLOCATING WORKORDERS?

13 A. Allocating Workorders are used to assign technology/information systems
14 costs to various functional areas within an operating company. For example,
15 for NSPM there are four Business Systems-related costs that are charged using
16 Allocating Workorders:

- 17 1) The work management system used by the Energy Supply business area
18 uses an Allocating Workorder to charge production FERC accounts;
19 2) The Electric Management System used by Energy Supply uses an
20 Allocating Workorder to charge system control and load dispatching
21 electric production, transmission and distribution FERC accounts;
22 3) The Gas Supervisory Control and Data Acquisition system used by the
23 Distribution business area for outage management uses an Allocating
24 Workorder to charge system control and load dispatching gas
25 transmission and distribution FERC accounts; and
26 4) The Network Services for the electric and gas distribution business
27 areas use an Allocating Workorder to charge the related FERC

1 accounts.

2
3 Q. WHAT IS THE BASIS OF ALLOCATING WORKORDERS?

4 A. operating company statistics relevant to the type of costs being allocated
5 provide the basis for the Allocating Workorders.
6

7 Q. WHEN ARE THESE STATISTICS UPDATED?

8 A. Allocating Workorders are updated annually starting with April business,
9 consistent with the updates to the operating company statistics used in XES
10 cost allocation factors.
11

12 Q. HAVE THE 2016 TEST YEAR ALLOCATING WORKORDER METHODOLOGIES AND
13 ALLOCATION FACTORS BEEN PROVIDED IN YOUR TESTIMONY?

14 A. Yes. The 2016 test year Allocating Workorder methodologies and percentages
15 are explained further in Section VI of the CAAM (Schedule 3), and the 2016
16 test year Allocating Workorder factors are provided in Exhibit____(ARD-1),
17 Schedule 7.
18

19 *3. Utility Allocations*

20 Q. WHAT IS THE PURPOSE OF COMMON UTILITY ALLOCATIONS?

21 A. Utility O&M allocations are developed to allocate NSPM common (electric
22 and natural gas) utility Administrative and General (A&G) costs charged to
23 FERC accounts 920 through 935 to the electric and natural gas utilities. They
24 are also used to allocate NSPM common (electric and natural gas) utility
25 customer accounting, customer information, and sales costs charged to FERC
26 accounts 901 through 917 to the electric and natural gas utilities.
27

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

3 A. The method used to allocate common customer-related utility costs between
4 electric and natural gas utilities is the number of customer bills. The method
5 used to allocate the commodity portion of the bad debt between electric and
6 natural gas utilities is associated revenues. This is the same method that was
7 used in NSPM's most recent electric and natural gas rate cases.
8

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

12 A. Yes. In the 2016 budget, A&G-related FERC accounts 925 and 926 were
13 allocated to the electric and natural gas utilities based on labor. However, all
14 other common A&G costs were allocated to the electric and natural gas
15 utilities based on a weighted three-factor formula comprised of revenue, utility
16 plant-in-service, and supervised O&M. (Supervised O&M refers to operations
17 and maintenance costs which are included in FERC account 500 through
18 FERC account 917.) The three-factor formula measures three distinct aspects
19 of the Company's operations and results in an appropriate assignment of costs
20 to the electric and natural gas utilities. This is consistent with NSPM's
21 hierarchical cost allocation principles described earlier in my testimony. Step 4
22 of these principles specifically addresses the use of the General Allocator
23 when no cost causative link exists.
24

25 Q. HAVE THE 2016 TEST YEAR O&M AND RATE BASE UTILITY ALLOCATION
26 METHODOLOGIES AND ALLOCATION FACTORS BEEN PROVIDED IN YOUR
27 TESTIMONY?

1 A. Yes. The 2016 test year O&M Utility Allocation methodology is explained in
2 Section VII of the CAAM (attached as Schedule 3) and the 2016 test year
3 Utility Allocation factors are further detailed in Exhibit____(ARD-1), Schedule
4 8. The 2016 test year utility rate base allocation methodology is explained in
5 Section VII of the CAAM, and the 2016 test year utility rate base allocation
6 factors are detailed in Ms. Heuer's Direct Testimony.

7
8 **D. Affiliate Transactions**

9 Q. PLEASE EXPLAIN THE BENEFITS THE ADMINISTRATIVE SERVICES AGREEMENT
10 (ASA) BETWEEN NSPM AND THE AFFILIATED UTILITY OPERATING
11 COMPANIES PROVIDES TO MINNESOTA ELECTRIC RATEPAYERS, AS REQUIRED
12 BY THE COMMISSION'S ORDER IN DOCKET NO. E002/AI-01-493.

13 A. The ASA allows certain activities that were not part of the Service Agreement
14 to be provided between operating companies at cost. The provision of
15 services by NSPM to other legal entities reduces overhead costs related to
16 those services, which further reduces the amount of cost recovered from
17 ratepayers. In addition, under the ASA, NSPM receives services from other
18 operating companies at cost, which eliminates the need for NSPM itself to
19 develop those services and incur the related overhead costs.

20
21 Q. WHAT TYPES OF O&M CHARGES ARE COVERED BY THE ASA IN THE 2016 TEST
22 YEAR BUDGET?

23 A. There is approximately \$246,000 of ASA charges from NSPM to NSPW in the
24 2016 test year. Exhibit____(ARD-1), Schedule 9 provides a description and the
25 dollar amount of the charges. The charges budgeted from NSPM to NSPW
26 primarily consist of two activities:

- 27
 - NSPM has a Hazardous Waste Consolidation facility at its Chestnut

1 Service Center in Minneapolis, Minnesota that gathers and processes
2 hazardous waste material from power plants and service centers in both
3 NSPM and NSPW. For 2016, NSPM is assigning a fully-loaded charge
4 of approximately \$138,000 to NSPW to perform these functions; and

- 5 • NSPM provides additional services to NSPW for the following services
6 and 2016 budgeted cost assignments: craft worker support for plant
7 maintenance, \$69,000; labor and facilities-related overheads, \$5,000 and
8 \$30,000; and fleet and other services of \$5,000.

9
10 Additionally, NSPW has a 2016 budgeted cost assignment to NSPM for
11 facilities-related overheads, siting and land rights and transmission control
12 center costs of \$13,000. In addition, approximately \$41,000 of 2016 ASA
13 charges consists of NSPM and Public Service Company of Colorado
14 transactions of \$40,000 and NSPM and Southwestern Public Service Company
15 transactions of \$1,000 for facilities and labor overheads.

16
17 Q. PLEASE EXPLAIN HOW COSTS ARE HANDLED FOR THE COMPANY'S TRANSCO
18 AFFILIATE.

19 A. A workorder system was created to segregate and track costs by Transco legal
20 entity and project. In this system, unique workorders are used to facilitate
21 billing directly between NSPM and the relevant Transco entity. In Docket
22 No. E002/AI-14-759, the Commission provided a mechanism for the
23 Company to report on an annual basis whether there were any assigned costs.
24 On September 2, 2015 we filed our first annual filing. If the Commission
25 makes any decisions in that docket that affect costs in this rate case, we will
26 make the necessary adjustments to reflect those decisions.

27

1 **E. Non-Regulated Business Activity Allocations**

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

3 A. The test year budget includes the following non-regulated business activities,
4 which are further described in Section III of NSPM's CAAM:

- 5 • HomeSmart;
- 6 • Customer Owned Street Lighting Maintenance; and
- 7 • Sherco Steam Sales to Liberty Paper Inc.

8

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

10 A. NSPM's non-regulated business activities account for approximately 0.57
11 percent of NSPM's total 2014 actual revenues and 0.22 percent of NSPM's
12 2014 actual operating expenses (excluding purchased fuel, power and gas
13 expenses). Exhibit____(ARD-1), Schedule 10 provides the supporting
14 calculations. The SEC Form 10-K for NSPM, provided as Exhibit____(ARD-
15 1), Schedule 11, is the source of the statistics used in these calculations, and
16 the applicable pages are referenced in the footnotes of Schedule 10.

17

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

20 A. Yes. Non-regulated business activity allocations ensure that: 1) the costs for
21 services provided to NSPM's non-regulated business activities are billed
22 representing a fully-distributed cost; and 2) gas and electric utility operations
23 are not subsidizing non-regulated business activities. In addition, NSPM
24 allocates a portion of its corporation costs using the labor-related overhead
25 and the corporate residual allocation discussed in this section to each non-
26 regulated business activity.

27

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

4 A. Yes. The test year allocation methodology is explained in Section VIII of the
5 CAAM, and the test year non-regulated business activity allocation factors are
6 listed in Exhibit____(ARD-1), Schedule 12.

7
8 **III. SUMMARY AND CONCLUSIONS**
9

10 Q. PLEASE SUMMARIZE YOUR TESTIMONY

11 A. Our cost allocation processes are designed to ensure that the costs to provide
12 service to our customers are recorded to the appropriate legal entities. They
13 emphasize the importance of accuracy, and facilitate business area
14 accountability and result in a reasonable and accurate forecast of the costs we
15 expect to incur. We note that the test year costs in this case reflect proposed
16 changes in cost assignment and allocation methods that are currently pending
17 before the Commission in Docket No. E,G002/AI-15-536. We will make any
18 necessary adjustments to test year costs once the Commission issues a
19 decision in that docket.

20
21 Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

22 A. Yes, it does.

Statement of Qualifications
Adam R. Dietenberger

I received a Bachelor of Science degree, with majors in accounting and finance, from University of Minnesota in 2004. I also hold an active CPA certificate from the State of Minnesota.

My current position with XES is Senior Manager, Service Company Accounting and Cash Processes. I am responsible for the general administration of XES, including accounting, billing, allocations, policies and procedures, service agreements, internal audits, external audits and external reporting to state and federal regulatory agencies. Additionally, I manage Xcel Energy's Cash Processes group, which is responsible for monitoring and reconciling the cash activity, long term debt and other related items for all Xcel Energy affiliates and subsidiaries.

I have been employed by XES since May 2008, first as a Senior Accountant, then as a Corporate Accounting Consultant, then as Manager, Corporate Accounting.

Prior to joining XES, I was employed by Deloitte LLP where I performed financial statement audits for companies in various industries including energy and utilities, healthcare, and manufacturing.

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

THIS SECOND AMENDMENT TO SERVICE AGREEMENT ("Second Amendment") is made and entered into as of the 15th day of December 2014, 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 was amended by a First Amendment to Service Agreement dated as of March 15, 2007 and approved in Minnesota Public Utilities Commission Docket No. E,G002/AI-08-760 ("First Amendment" and the Original Service Agreement as amended by the First Amendment, 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.

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

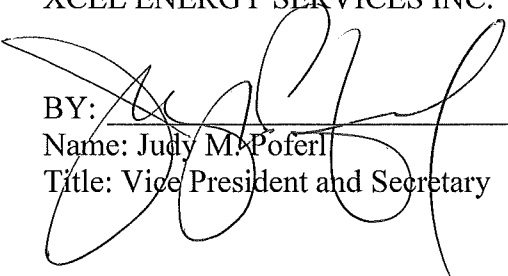
NOW THEREFORE, for and in consideration of the mutual covenants contained in this Second Amendment and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties agree as follows:

1. Appendix A to the Amended Service Agreement is deleted in its entirety and replaced with the contents of Schedule 1 to this Second Amendment.
2. Except as expressly amended by this Second Amendment, all other provisions of the Amended Service Agreement remain in full force and effect.
3. This Second 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 Second Amendment to Service Agreement to be executed as of the date and year first above written.

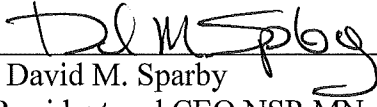
XCEL ENERGY SERVICES INC.

BY: 

Name: Judy M. Pofert

Title: Vice President and Secretary

NORTHERN STATES POWER
COMPANY (MINNESOTA)

BY: 

Name: David M. Sparby

Title: President and CEO NSP-MN

[SIGNATURE PAGE TO SECOND AMENDMENT TO SERVICE AGREEMENT]

Schedule 1

Northern States Power Company

Cost Assignment and Allocation Manual

August 2015

Northern States Power Company Cost Assignment and Allocation Manual

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I. INTRODUCTION

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

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

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

NSPM owns the following direct subsidiaries: United Power and Land Co., which holds real estate; Private Fuel Storage LLC, which is involved in developing a private temporary spent nuclear fuel facility; and NSP Nuclear Corporation which holds NSPM’s interest in Nuclear Management Co., LLC, (NMC), which is the former holder of NSPM nuclear licenses. The nuclear licenses held by NMC have been transferred to NSPM, and the Company is waiting on Nuclear Regulatory Commission authorization to dissolve NMC. NSPM is a wholly owned subsidiary of Xcel Energy.

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

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

- The Service Company is listed as an affiliate company in the Affiliate Transaction section for the services it provides to NSPM.

- The Service Company and all other companies in the Xcel Energy Inc. holding company system of companies are included in the Corporate Organization to provide a listing of all affiliates of NSPM.
- The Service Company is also referenced in the Cost Assignment and Allocation Process section because this section covers processes that may cross multiple legal entities.

The NSPM CAAM contains the following sections:

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

DEFINITIONS

Abbreviations or Acronyms

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

A&G.....	Administrative and General
AFUDC.....	Allowance for Funds Used During Construction
CAAM.....	Cost Assignment & Allocation Manual
Commission.....	Minnesota Public Utility Commission
FERC.....	Federal Energy Regulatory Commission
FICA.....	Federal Insurance Contributions Act
FUTA.....	Federal Unemployment Tax Act
HR.....	Human Resources
IT.....	Information Technology
JDE.....	J.D. Edwards Financial System

Abbreviations or Acronyms (continued)

NSPM or the Company.....	Northern States Power Co., a Minnesota corp.
NSPW.....	Northern States Power Co., a Wisconsin corp.
O&M.....	Operations and Maintenance
PassPort.....	Indus PassPort Integrated Supply Chain/Accounts Payable System
PSCo	Public Service Company of Colorado, a Colorado corp.
RTU.....	Remote Terminal Units
SCADA.....	Supervisory Control and Data Acquisition
Service Company.....	Xcel Energy Services Inc.
SPS.....	Southwestern Public Service Company, a New Mexico corp.
SUTA.....	State Unemployment Tax Authority
Xcel Energy or the Holding Company.....	Xcel Energy Inc.

Terms

The following terms are used within the CAAM document:

Accounts Payable – the Payment and Reporting Department of Xcel Energy Services Inc. (the “Service Company”).

Administrative and General (“A&G”) – includes activity in Federal Energy Regulatory Commission (“FERC”) accounts 920-935, Administrative and General Expenses.

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

J.D. Edwards Financial System (“JDE”) Business Unit – describes where a transaction will be recognized in an organization. JDE Business Units are assigned only to one company or legal entity and are the lowest organizational reporting level for the Company.

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

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

Supply Chain – the Supply Chain Department of the Service Company.

Workorder – accumulates costs for capital, expense or to be further allocated.

II. CORPORATE ORGANIZATION

OVERVIEW OF COMPANY SYSTEM

Xcel Energy Inc., a Minnesota corporation, is a registered holding company. The Parent directly owns four operating public utility subsidiaries that serve electric, natural gas, thermal and propane customers in eight states. These four utility subsidiaries are NSPM; Northern States Power Company, a Wisconsin corporation (“NSPW”); Public Service Company of Colorado, a Colorado corporation (“PSCo”); and Southwestern Public Service Company, a New Mexico corporation (“SPS”). Xcel Energy Inc., is also the parent company of WestGas InterState, Inc., an interstate natural gas pipeline company and three transmission-only operating companies, Xcel Energy Southwest Transmission Company, LLC (“XEST”), Xcel Energy Transmission Development Company, LLC (“XETD”), and Xcel Energy West Transmission Company, LLC (“XEWI”), all of which are regulated by the Federal Energy Regulatory Commission (“FERC”).

Their collective service territories include portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin.

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

LIST OF REGULATED & NONREGULATED AFFILIATES (as of August 31, 2015)

Xcel Energy Inc.

- Northern States Power Company (MN)
 - NSP Nuclear Corporation
 - Nuclear Management Co. LLC
 - Private Fuel Storage LLC
 - United Power and Land Company
- Northern States Power Company (WI)
 - Chippewa and Flambeau Improvement Company
 - Clearwater Investments, Inc.
 - Shoe Factory Holding LLC
 - Woodsedge Eau Claire LP
 - NSP Lands, Inc.
- Public Service Company of Colorado

1480 Welton, Inc.
Green and Clear Lakes Company
P.S.R. Investments, Inc.
Beeman Irrigating Ditch and Milling Company
Consolidated Extension Canal Company
East Boulder Ditch Company
Fisher Ditch Company
Gardeners Mutual Ditch Company
Hillcrest Ditch and Reservoir Company
Las Animas Consolidated Canal Company
United Water Company
Southwestern Public Service Company
Xcel Energy Foundation
Xcel Energy Services Inc.
WestGas InterState, Inc.
Xcel Energy WYCO Inc.
WYCO Development, LLC
Xcel Energy International Inc.
Xcel Energy Markets Holdings Inc.
e prime, inc.
Young Gas Storage Company, Ltd.
Xcel Energy Retail Holdings Inc.
Xcel Energy Performance Contracting Inc.
Reddy Kilowatt Corporation
Xcel Energy Ventures Inc.
Eloigne Company
Bemicil Townhouse LP
Chaska Brickstone LP
Crown Ridge Apartments LP
Cottage Court LP
Dakotah Pioneer LP
East Creek LP
Edenvale Family Housing LP
Fairview Ridge LP
Farmington Family Housing LP
Farmington Townhome LP
Hearthstone Village LP
J&D 14-93 LP
Jefferson Heights of Zumbrota LP
Lauring Green LP
Links Lane LP
Lyndale Avenue Townhomes LP
Mahtomedi Woodland LP
Mankato Townhomes LLP
Marvin Garden LP
Moorhead Townhomes LP
Park Rapids Townhomes LP
Rochester Townhome LP

Rushford Housing LP
RWIC Credit Fund LP – 1993
Safe Haven Homes, LLC
Shade Tree Apartments LP
Shakopee Boulder Ridge LP
Shenandoah Woods LP
St. Cloud Housing LP
Sioux Falls Partners LP
Tower Terrace LP
Wyoming LP II
Xcel Energy Communications Group Inc.
NCE Communications, Inc.
Seren Innovations, Inc.
Xcel Energy Wholesale Group Inc.*
Quixx Corporation*
Quixx Carolina, Inc.*
Quixxlin Corp.*
Quixx Linden, L.P.*
Quixx Linden, L.P.*
Xcel Energy Transmission Holding Company, LLC
Xcel Energy Southwest Transmission Company, LLC
Xcel Energy Transmission Development Company, LLC
Xcel Energy West Transmission Company, LLC

* Company is being classified in discontinued operations

III. DESCRIPTION OF SERVICES

OVERVIEW

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

REGULATED SERVICES

ELECTRIC UTILITY

Electric – Residential

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

Electric – Commercial and Industrial

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

Electric – Street Lighting

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

Electric - Other Sales to Public Authorities

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

Electric - Resale

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

Electric - Interdepartmental

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

Off-System Electric Sales

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

OTHER ELECTRIC OPERATING REVENUE

Rent from Electric Property

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

Interchange Agreement

The Interchange Agreement is a FERC-approved rate schedule that provides for the intercompany sharing of production and transmission costs of NSPM and NSPW. NSPM and NSPW operate an integrated production and transmission system, and the Interchange Agreement provides for the costs of that integrated system to be shared between NSPM and NSPW based upon demand and energy ratios reflecting usage by the respective companies. The costs associated with this agreement reside in FERC account 557, Other Power Supply Expenses; and FERC 566, Miscellaneous Transmission Expenses. The revenues reside in FERC account 456, Other Electric Revenues.

Joint Operating Agreement

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

Miscellaneous Electric Revenue

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

GAS UTILITY

Gas - Residential

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

Gas – Commercial and Industrial

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

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

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

Gas – Interruptible

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

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

Gas – Large Firm Transportation

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

Gas – Interruptible Transportation

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

Gas – Negotiated Transportation

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

Gas – Interdepartmental

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

Gas – Limited Firm

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

Gas – Daily Balancing Service

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

OTHER GAS REVENUE

Miscellaneous Gas Revenue

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

COMMON ELECTRIC AND GAS REVENUE

Late Payments Fees/Miscellaneous Service Revenues

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

CIP Incentives

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

ConnectSmart

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

Hazardous Waste Disposal

NSPM has a Hazardous Waste Consolidation facility at Chestnut Service Center in Minneapolis, Minnesota. The facility gathers hazardous and specially regulated waste material from power plants and service centers in both NSPM and NSPW service territories, consolidates the material, and packages it for shipment to a permanent and appropriately licensed waste disposal site.

NONREGULATED BUSINESS ACTIVITIES

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

HomeSmart

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

Customer Owned Street Lighting Maintenance

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

Sherco Steam Sales to Liberty Paper Inc

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

IV. TRANSACTIONS WITH AFFILIATES

OVERVIEW

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

The sections below separately detail the nature and terms of transactions for services and asset transfers provided by NSPM to its affiliates, as well as services and asset transfers provided to NSPM by each of its affiliates. This section includes descriptions of affiliate transactions only, and does not include convenience payments, which are payments made by an operating company or the Service Company on behalf of another operating company or affiliate that are not the result of the operating company or the Service Company providing a service (a good, product or service) to an operating company or affiliate.

As noted in the Introduction, NSPM receives administrative, management, accounting, legal, engineering, environmental and other support services from the Service Company. The Service Company provides the services to the Xcel Energy Inc. subsidiaries, at cost, pursuant to service agreements and allocation methods that were approved by the SEC under PUHCA 1935 prior to implementation. The federal supervision over utility holding companies was transferred from the SEC to FERC in 2005.

The cost allocation methodologies under which the Service Company costs are assigned and allocated are set forth in the service agreement, and while they are not the subject of this NSPM CAAM, they are included in this section to provide as complete a picture as possible of all affiliate transactions. The NSPM Service Agreement is updated from time to time with the most recent updates being approved in Docket E,G002/AI-14-234 on November 20, 2014. NSPM's affiliate transactions currently consist primarily of transactions with the Service Company for these services.

Terms of Transactions

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

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

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

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

SERVICES PROVIDED BY NSPM TO AFFILIATES

Nature of Transactions

Terms

NSPW

Operations and Maintenance – Production, decommissioning and transmission costs associated with the Interchange Agreement (FERC Docket No. ER15-1575-000).

Fully distributed cost

Supervisory Control and Data Acquisition (“SCADA”) and Gas Dispatch – Sharing of SCADA costs in accordance with Docket G-002/ AI-94-831.

Fully distributed cost

Materials and Supplies – Materials and supplies, including any associated freight, purchase loadings and warehouse loadings.

Fully distributed cost

Miscellaneous – Miscellaneous other charges, including labor, associated loadings, and lease costs.

Fully distributed cost

PSCo

Materials and Supplies – Materials and supplies, including any associated freight, purchase loadings and warehouse loadings.

Fully distributed cost

Joint Operating Agreement – Margin sharing associated with proprietary energy trading activities.

Fully distributed cost

Miscellaneous – Miscellaneous other charges, including labor, associated loadings, and lease costs.

Fully distributed cost

SERVICES PROVIDED BY NSPM TO AFFILIATES (continued)Nature of TransactionsTerms**SPS**

Materials and Supplies – Materials and supplies, and any associated freight, purchase loadings and warehouse loadings.

Fully distributed cost

Joint Operating Agreement – Margin sharing associated with proprietary energy trading activities.

Fully distributed cost

Miscellaneous – Miscellaneous other charges, including labor and associated loadings and lease costs.

Fully distributed cost

Xcel Energy Inc.

Miscellaneous - Miscellaneous other charges, including 401(k) match and a dividend on common stock

Fully distributed cost

SERVICES PROVIDED BY AFFILIATES TO NSPM**Xcel Energy Services Inc.**

The nature, frequency and terms of the services provided by the Service Company to NSPM are as follows:

Nature of Transactions

*Executive Management Services** – Represents charges for Xcel Energy Inc. executive management and services, including, but not limited to, officers of Xcel Energy Inc.

Terms

Fully distributed cost

*Investor Relations** – Provides communications to investors and the financial community. Coordinates the transfer agent and shareholder record keeping functions and plans the annual shareholder meeting.

Fully distributed cost

*Internal Audit** – Reviews internal controls and procedures to ensure assets are safeguarded and transactions are properly authorized and recorded. Evaluates contract risks.

Fully distributed cost

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

Fully distributed cost

*Claims Services** – Provides claims services related to casualty, public and company claims.

Fully distributed cost

*Corporate Communications** – Provides corporate communications, speech writing and coordinates media services. Provides advertising and branding development for the companies within the Xcel Energy Inc. system. Provides labor to track all contributions made on behalf of the Xcel Energy Inc. system.

Fully distributed cost

*Employee Communications** – Develops and distributes communications to employees.

Fully distributed cost

*Corporate Strategy & Business Development** – Facilitates development of corporate strategy and prepares strategic plans, monitors corporate performance and evaluates business opportunities. Develops and facilitates process improvements.

Fully distributed cost

SERVICES PROVIDED BY AFFILIATES TO NSPM (continued)

Nature of Transactions

*Government Affairs** – Monitors, reviews and researches government legislation.

Terms

Fully distributed cost

*Facilities & Real Estate** – Operates and maintains office buildings and service centers. Procures real estate and administers real estate leases. Administers contracts to provide security, housekeeping and maintenance services for such facilities. Procures office furniture and equipment.

Fully distributed cost

*Facilities Administrative Services** – Includes but is not limited to the functions of Mail Delivery, Duplicating and Records Management.

Fully distributed cost

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

Fully distributed cost

*Supply Chain Special Programs** – Develops and implements special programs utilized across the company such as procurement cards, travel services, and compliance with corporate MWBE (minority women business expenditures) program goals.

Fully distributed cost

*Human Resources ("HR")** – Establishes and administers policies related to employment, compensation and benefits. Maintains Human Resources 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 Human Resources support services.

Fully distributed cost

*Finance & Treasury** – 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.

Fully distributed cost

SERVICES PROVIDED BY AFFILIATES TO NSPM (continued)Nature of TransactionsTerms

<i>Accounting, Financial Reporting & Taxes*</i> – 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.	Fully distributed cost
<i>Payment & Reporting*</i> – Processes payments to vendors and prepares statistical reports.	Fully distributed cost
<i>Receipts Processing*</i> – Processes payments received from customers of the Operating Companies and affiliates.	Fully distributed cost
<i>Payroll*</i> – Processes payroll including but not limited to time reporting, calculation of salaries and wages, payroll tax reporting and compliance reports.	Fully distributed cost
<i>Rates & Regulation*</i> – 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.	Fully distributed cost
<i>Energy Supply Engineering and Environmental*</i> – Provides engineering services to the generation business. Establishes policies and procedures for compliance with environmental laws and regulations. Researches emerging environmental issues and monitors compliance with environmental requirements. Oversees environmental cleanup projects.	Fully distributed cost
<i>Energy Supply Business Resources*</i> – Provides performance, specialists and analytical services to the Operating Companies' generation facilities.	Fully distributed cost

SERVICES PROVIDED BY AFFILIATES TO NSPM (continued)

<u>Nature of Transactions</u>	<u>Terms</u>
<i>Energy Markets Regulated Trading & Marketing*</i> – Provides electric trading services to the Operating	Fully distributed cost

Companies' electric generation systems including load management, system optimization and resource acquisition.

<i>Energy Markets-Fuel Procurement*</i> – Purchases fuel for Operating Companies electric generation systems (excluding nuclear).	Fully distributed cost
<i>Energy Delivery Marketing*</i> – Develops new business opportunities and markets the products and services for the Delivery Business Unit.	Fully distributed cost
<i>Energy Delivery Construction, Operations & Maintenance*</i> – Constructs, maintains and operates electric and gas delivery systems.	Fully distributed cost
<i>Energy Delivery Engineering/Design*</i> – Provides engineering and design services in support of capacity planning, construction, operations and material standards.	Fully distributed cost
<i>Marketing & Sales*</i> – 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.	Fully distributed cost
<i>Customer Service*</i> – Provides service activities to retail and wholesale customers. These services include meter reading, customer billing, call center and credit and collections.	Fully distributed cost
<i>Aviation Services*</i> – Provides aviation and travel services to employees.	Fully distributed cost
<i>Fleet*</i> – Oversees the Operating Companies' Fleet Services Group.	Fully distributed cost

SERVICES PROVIDED BY AFFILIATES TO NSPM (continued)

<u>Nature of Transactions</u>	<u>Terms</u>
<i>Business Systems*</i> – Provides basic information technology services such as: application	Fully distributed cost

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

* Corporate Governance activities within this Service Function will be allocated using the average of the Revenue Ratio with intercompany dividends assigned to Xcel Energy Inc., Full Time Equivalent Hours Including Overtime, and the Total Assets Ratio including Xcel Energy Inc.'s per book assets.

V. COST ASSIGNMENT AND ALLOCATION PROCESS

OVERVIEW

This section of the CAAM provides an overview of the cost assignment and allocation principles of NSPM and the accounting processes within the monthly accounting close and within the JD Edwards ("JDE") general ledger system, including both system generated processes and manual processes, used to assign and allocate costs between the regulated services and the nonregulated business activities of NSPM. Each major step of the accounting process is identified in the following paragraphs and will be explained in conjunction with the process flowchart on page V-18. Each major step results in costs being either directly assigned or allocated to regulated services and nonregulated business activities. The result of applying these principles is that each company, utility, jurisdiction and nonregulated business activity pays the full cost for any service provided to support their respective operations.

Many of the assignment and allocation processes occur either in the Service Company or are administered by Service Company personnel. As noted in the Introduction, the Service Company provides these services "at cost" to the Xcel Energy Inc. subsidiaries, including NSPM, pursuant to service agreements and allocation methods that were approved by the SEC under PUHCA 1935 prior to implementation. The federal supervision over utility holding companies was transferred from the SEC to FERC in 2005.

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

COST ASSIGNMENT AND ALLOCATION PRINCIPLES

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

The hierarchical cost assignment and allocation principles are:

1. Tariffed rate shall be used to value tariffed services provided.
2. Costs shall be directly assigned to either regulated or nonregulated business activities whenever possible.
3. Costs that cannot be directly assigned are common costs, which shall be grouped into homogeneous cost categories. Each cost category shall be allocated based on direct analysis of the origin of the costs whenever possible. If direct analysis is not possible, common costs shall be allocated based upon an indirect cost-causation.

4. Whenever neither direct or indirect measures of cost causation can be found, the cost category shall be allocated based upon a general allocator.

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

ACCOUNTING PROCESSES

The flowchart on page V-18 provides a high level overview of the various major steps in the monthly accounting close process and the various systems used to generate the books and records of NSPM. Several steps within the process have allocations imbedded in them and are therefore included to provide as much information as possible to promote an understanding of the major steps where direct assignment and allocation can occur.

FEEDER SYSTEMS (Addendum A, Flowchart Item 1)

The monthly close process initially starts with the collection of accounting information from numerous feeder systems as identified in Item 1 on the flowchart. Feeder systems gather accounting transactions on a monthly basis and 'feed,' or pass, those accounting transactions to JDE to build the monthly books and records of each utility operating company or affiliate of Xcel Energy Inc. that uses the JDE general ledger system.

There are two basic types of transactions in the feeder systems:

- The first basic group consists of individual transactions fed directly to JDE. These transactions come from the PowerPlan System ("PowerPlan"), the Indus PassPort Integrated Supply Chain/Accounts Payable System ("PassPort") and the Maximo System.

PowerPlan System

PowerPlan tracks all capital projects and work order expenditures for Xcel Energy Inc. utility operating companies on a life-to-date basis. Once expenditures are recorded on the books of the appropriate legal entity, PowerPlan generates the overhead allocations and if appropriate the AFUDC, and applies the overheads to the individual work orders. In addition, PowerPlan calculates monthly depreciation by legal entity and handles the transfer of work orders from FERC account 107, Construction Work in Progress, to FERC account 106, Completed Construction-Not Unitized, to FERC account 101, Utility Plant in Service. The transfer of non-utility costs is within FERC account 121, Non-Utility Property using sub accounts; from FERC account 12140, Non-Utility Construction Work in Progress, to FERC account 12112, Non-Utility Completed Construction-Not Unitized, to FERC account 12111, Non-Utility Plant in Service-Unitized.

Indus PassPort Integrated Supply Chain/Work Management/Accounts Payable System

The Supply Chain/Work Management components are used for inventory and work management processes by the Transmission, Distribution, and Nuclear business areas. This system is used to maintain inventory records by legal entity and bill materials to operation and maintenance jobs or capital jobs. In addition, the system is used as a work management tool by these business areas too. The system is also used to process and pay invoices of NSPM.

Maximo System

The Maximo system is an inventory and work management system used by the Energy Supply business area across the operating companies. This system is used to maintain inventory records by legal entity and bill materials to operation and maintenance jobs or capital jobs. In addition, the system is used as a work management tool by the Energy Supply business area.

- The second basic group of transactions is where costs are developed by either applying an internal billing rate to a unit of measure or by an allocation within a process, which charges costs to a legal entity, business area and regulated or nonregulated business activity. Transactions from Labor Distribution, Transportation Distribution and Information Technology are some of the major processes that fall within this category. Each of these distribution processes may have one or more internal billing rates to charge costs to internal users. Individual transactions are generated within any one of these distribution processes to charge costs to the regulated services and nonregulated business activities within an operating company or affiliate. For example, labor distribution charges can be directly assigned to the nonregulated JDE accounts for HomeSmart within NSPM and linked directly to FERC account 417.1, Expenses from Nonutility Operations.

The following processes are described in greater detail later in this section.

- o Labor Distribution
- o Labor Overheads
- o Aviation Distribution
- o Stores/Warehouse Overhead
- o Purchasing Overhead
- o Transportation Distribution
- o Accounts Payable
- o Information Technology
- o Shared Assets Distribution
- o Facilities Distribution
- o Money Pool
- o Customer Billing

JDE GENERAL LEDGER PROCESSING (Addendum A, Flowchart Item 2)

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

All of the transactions from the above processes are gathered together in JDE. Once all the transactions are recorded in JDE there are multiple processing steps within JDE, including Service Billings and Utility Allocations. These steps specifically affect regulated services and nonregulated business activities and are detailed separately on the following pages.

SERVICE BILLING (Addendum A, Flowchart Item 3)

The Service Billing function within JDE is the accounting process that is used primarily to bill the operating companies and affiliates for Service Company charges. The process is also used to bill charges from one operating company or affiliate to another operating company or affiliate and from one business area to another business area within the same legal entity.

The Service Billing function bills the Service Company direct charges and indirect allocations from the Service Company legal entity to the operating companies or affiliates. As discussed earlier in this document, the indirect allocation methods have been approved. All labor billed includes labor overheads. Whenever possible, costs related to the nonregulated business activities within an operating company or affiliate are directly charged to JDE accounts, which are linked directly to the 417 FERC accounts.

The Service Billing function may also include transactions billed out of the feeder systems, transactions billed between affiliates and transactions billed within an affiliate. For example, transactions billed from NSPM to PSCo for emergency work would flow through Service Billing.

CLEARING ACCOUNTS (Addendum A, Flowchart Item 4)

The clearing account process is being noted in this section of the CAAM because it uses the functionality of the allocation process within JDE to move the net of all expenditures and other clearings recorded on the income statement to the balance sheet for processes such as labor overheads.

ALLOCATING WORK ORDERS (Addendum A, Flowchart Item 5)

The Allocating Work Order functionality is a feature developed as part of JDE that is currently used by NSPM to allocate certain information technology costs that support multiple utility processes to the appropriate FERC functional accounts related to these processes. NSPM has four allocating work orders, which are described in Section VI.

UTILITY ALLOCATIONS (Addendum A, Flowchart Item 6)

NSPM's costs are directly assigned or allocated to electric, gas or nonregulated business activities whenever possible or charged as common and then allocated to the electric and gas utilities using Utility Allocations. Common utility costs are grouped into two categories: (1) O&M utility allocations and (2) rate base and non-O&M utility allocations. The O&M utility allocations are done monthly within the JDE system and are explained below. A study is performed annually, as well as for rate case filing purposes, to identify all rate base and non-O&M costs that are common among the utility operations of NSPM. These costs are then allocated among the utilities according to the allocations described in Section VII.

NONREGULATED BUSINESS ACTIVITY ALLOCATIONS (Addendum A, Flowchart Item 7)

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

JURISDICTIONAL ALLOCATIONS (Addendum A, Item 8)

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

Service: LABOR DISTRIBUTION

Description: Wages and salaries of employees engaged in work on behalf of regulated services and nonregulated activities are assigned or allocated based on positive time reporting through the TIME labor distribution system. Positive time reporting requires each employee to report the hours worked for each day using one-sixth of an hour or greater increments, while providing for aggregation of time when appropriate. Under this method, employees' time is reported on the basis of accounting codes related to specific operating utility companies or affiliates and/or functional services.

Provider of Service: Service Company
Operating companies or affiliates

User of Service: Operating companies or affiliates, including utility operations, jurisdictions, and nonregulated activities within an operating company.

Method of Allocation: All bi-weekly and semi-monthly employees' labor expenses are recorded by company personnel on time sheets and entered into various time reporting systems, all of which feed into the TIME labor distribution system. The employee submitting the time sheet is responsible for coding the JDE account numbers to charge the appropriate operating companies or affiliates, business function (e.g., capital, operations, maintenance, clearing, purchasing and/or warehousing, etc.) and regulated or nonregulated operations.

Time sheets must be completed and delivered to the employee's designated timekeeper by certain cut-off dates established by the Payroll Department. The employee's supervisor or manager is responsible for reviewing and approving all time sheets submitted, and verifying that the employee is using the correct JDE account numbers.

The TIME labor distribution system used for bi-weekly employees includes the distribution of actual paid and accrued labor dollars/hours to the JDE account number charged based on the hours worked. Accrual of payroll is to facilitate the recording of labor costs on a calendar month basis. This includes any reversal of the prior month's accrual. The charge of labor dollars for semi-monthly employees to JDE account numbers is based on a distribution of the monthly salary of the employee.

Service: **LABOR OVERHEADS**

Description: Employee labor overhead costs are captured in the following categories:

Benefit employees:

- Non-productive labor costs (vacation, sick, holiday, etc.)
- Pension (401k match, qualified and non-qualified pension, , NMC employer retirement contribution, and retirement related consulting)
- Insurance (active and retiree healthcare, life and LTD insurance premiums, miscellaneous benefit program and LTD benefits for former or inactive employees before retirement)
- Workers compensation
- Incentives (Incentives are a labor overhead for Service Company, PSCo, and SPS. Incentives for NSPM and NSPW are charged directly to FERC accounts 920 and 517).
- Payroll taxes (FICA, FUTA, SUTA)

Non-Benefit employees:

- Payroll taxes (FICA, FUTA, SUTA)

Provider of Service: Service Company
Operating companies or affiliates

User of Service: Operating companies or affiliates, including utility operations, jurisdictions, and non-regulated activities within an operating company.

Method of Allocation: Labor overheads are allocated within a legal entity by calculating a separate loading rate for each cost category identified in the "Description" section above.

For each legal entity and each category, the costs are allocated based on a single-factor formula that is comprised of total estimated costs for the category divided by total estimated productive labor costs.

Legal entity specific rates for each category are entered into the TIME labor distribution system and applied to productive labor charges as appropriate for each resource type. Labor loadings applied to labor charges follow the labor charges. For example, Service Company labor overheads follow Service Company labor and NSPM labor overheads follow NSPM labor.

Labor overhead rates are updated each month to ensure the actual costs are distributed. Additionally, a year-end true up

is recorded to bring the overhead clearing accounts to zero for the calendar year.

Service: **AVIATION DISTRIBUTION**

Description: The Aviation Services department in the Service Company is responsible for managing and operating the two corporate leased aircraft used by the Xcel Energy system of companies. Costs include: pilot salaries and labor overheads, operation and maintenance costs, lease costs and administrative and general costs associated with managing the Aviation Services department.

Provider of Service: Service Company

User of Service: Service Company, operating companies or affiliates, including utility operations, jurisdictions, and nonregulated activities within an operating company.

Method of Allocation: Aviation costs are allocated using the average of the Revenue Ratio with intercompany dividends assigned to Xcel Energy Inc., Full Time Equivalent Hours Including Overtime, and the Total Assets Ratio including Xcel Energy Inc.'s per book assets.
Any spousal use of the aircraft must be approved and is billed to the holding company.

Service: STORES/WAREHOUSE OVERHEAD

Description: Inventory warehousing costs, including labor, supervision, materials and supplies are allocated through pools specific to business area as an overhead on materials and supplies as materials and supplies are issued from/returned to a storeroom or warehouse.

In the Energy Supply business area, the inventory warehousing costs related to the Sherco plant are direct charged to station operating and maintenance (O&M) and capital projects (when dedicated capital project support is performed).

Provider of Service: Service Company
Operating companies

User of Service: Operating companies or affiliates, including utility operations, jurisdictions, and nonregulated activities within an operating company.

Method of Allocation: The overhead costs for inventory items as noted above and associated adjustments are accumulated within the Supply Chain, Energy Supply or Nuclear business area. These accumulated overhead costs are allocated to material issuances/returns from the storeroom using the same account coding where the materials were originally charged. Certain allocated overhead expenses are capped at \$3,500 per purchase order or purchase order line or contract payment authorization.

Each business area has a separate pool for each operating company and sets an overhead application rate for budgeting for the year based on projected overhead and materials activity.

During the year as actuals are recorded, the balances in the undistributed stores/warehouse clearing accounts are compared to the materials activity and historical trending and a new rate is determined.

Service: PURCHASING OVERHEAD

Description: The Supply Chain organization in the Service Company has the responsibility for distributing the corporate purchasing and contract services costs to the functional area(s) of the operating companies or affiliates along with the cost of the materials and supplies ordered. Purchasing costs are made up of activities such as developing requisitions, contracts and purchase orders to procure materials and services and manage supplier relationships, negotiating complex procurement agreements/contracts for strategic supplier partnerships and service contracts, monitoring supplier performance, and managing purchase records, supplier qualification records and the supplier diversity program.

The purchasing function is done in two different areas of the company. Supply Chain and Nuclear uses PassPort for companywide purchases and the Energy Supply business area uses Maximo for production related purchases.

Provider of Service: Service Company
Operating companies

User of Service: Service Company, operating companies and affiliates, including utility operations, jurisdictions, and nonregulated business activities within an operating company.

Method of Allocation: Costs are collected in clearing accounts on the Service Company and the operating companies and cleared via an overhead loading. The loading follows the accounting for certain purchases with the offset going to a contra clearing account.

For PassPort and Maximo, certain purchases are loaded with the purchasing overhead up to a \$3,500 cap. The \$3,500 cap is calculated based on the value of the purchase order for purchase order payments, the total value of the contract payment authorization or the total value of the invoice for the request for payment. For PassPort, the loading is calculated and a new record is posted to the general ledger as a detail item. For Maximo, the loading is calculated once a month and shows up as a separate summary transaction on the general ledger.

Service: TRANSPORTATION DISTRIBUTION

Description: The Fleet Services department in the Service Company is responsible for managing the fleet assets owned by the operating companies. Fleet assets are vehicle units that are organized into class categories, which group together vehicles similar in nature. These classes are also grouped on vehicle features and costs of the units. For example, automobiles are classified by compact, mid-sized or intermediate. Pickups are grouped by ½ ton 2-wheel drive, ½ ton 4-wheel drive, etc. Each of these classes will have its own unique individual fixed rate to bill users.

The Transportation Distribution system bills internal functional areas of operating companies and affiliates for the cost of using vehicles or associated equipment. It distributes the operating costs related to vehicle units using usage rates based on the type of unit.

Fleet costs included in the calculation of the monthly billing rate include: licensing taxes and fees, lease costs, material and labor costs for maintenance and repair, fuel, labor loadings, and overhead for overall management of the Fleet Services department that includes labor, facilities, insurance utilities, computer, phone and office supplies.

Provider of Service: Service Company
Operating companies

User of Service: Service Company, operating companies or affiliates, including utility operations, jurisdictions and nonregulated business activities within an operating company.

Method of Allocation: The Transportation Distribution system bills each user for units assigned based on the monthly rates calculated by class category. Each month a validation report is reviewed to ensure all costs are billed and any invalid accounts are reviewed and corrected. Rates are adjusted periodically to account for clearing imbalances caused by variable factors such as fuel prices.

Service: INFORMATION TECHNOLOGY

Description: The Business Systems organization in the Service Company is responsible for managing the corporate Information Technology ("IT") assets and services of Xcel Energy. Business Systems bills out O&M and capital costs related to Xcel Energy's corporate IT equipment and services incurred internally, as well as costs incurred through third party vendors. Costs include system O&M, desktop services, phone service, servers, infrastructure costs, software, software licensing, system design and implementation, labor and labor overheads, etc.

Provider of Service: Service Company

User of Service: Service Company, operating companies or affiliates, including utility operations, jurisdictions and nonregulated activities within an operating company.

Method of Allocation: IT costs are charged through several different methods.

Costs are charged directly to the operating companies, affiliates, jurisdictions or nonregulated activities on the invoice, timesheet, expense report or other source document to the company(ies) benefiting from the service whenever possible.

If costs cannot be charged directly to an operating company, affiliate, jurisdiction or nonregulated activity, the costs are charged to the appropriate Service Company indirect allocation workorder that will assign the costs using a cost causative method to the companies benefiting from the system application or service.

For costs that can be identified as benefiting a particular service function, those services would be charged to a Service Company indirect allocation workorder using the approved allocation factor for that business area.

Service: ACCOUNTS PAYABLE

Description: The Payment and Reporting Department (Accounts Payable), in the Service Company, processes several types of documents for payment on behalf of the operating companies and affiliates. Accounts Payable uses PassPort and Concur to process invoice payments associated with purchase orders, contracts, requests for payment (non-purchase orders, non-contract invoices) and employee payments, including per diem charges, suggestion system award payments and employee expense reimbursements.

The charges for goods, materials and services, which post directly to the general ledger of each operating company and affiliate, differ for each type of document.

Provider of Service: Service Company

User of Service: Service Company, operating companies and affiliates, including utility operations, jurisdictions, and nonregulated activities within an operating company.

Method of Allocation: Within each operating company and affiliate, charges are directly assigned whenever possible. Charges may be distributed to multiple business functions or business areas based on the accounting code(s) on each document. If necessary, costs may be allocated using any surrogate measure that has a logical or observable correlation to the charges in the quantities sold, the services that caused the cost to be incurred or that benefited from the cost. The following are examples of some of the logical or observable correlations used to allocate costs contained on Accounts Payable documents:

- Quantity (units, count, etc.)
- Measurement or size (length, space, columnar inch, etc.)
- Volume (barrels, gallons, liters, etc.)
- Weight (ounce, pound, ton, etc.)
- Hours (hours of professional or contract services)
- Labor dollars (charge is in the same proportion as the labor hours of the department)
- Number of customers, meters, employees, etc.
- Revenue dollars
- Plant in service
- Square footage

Service: SHARED ASSETS DISTRIBUTION

Description: Shared assets are defined as capitalized assets that are owned by one legal entity but are used for the benefit of multiple entities. This would include land structures and improvements, office furniture and equipment, computer and communication equipment, and some software systems that are used by employees in the performance of their jobs.

Provider of Service: Operating companies or affiliates

User of Service: Service Company, operating companies and affiliates

Method of Allocation: All allocations are billed through the Service Company and either charged to a Service Company indirect workorder that will assign the costs using a cost causative method to the companies benefiting shared assets. For IT related assets, the costs will be charged to the system application or service work order. For facility assets, the costs will be charged to the Service Company facilities clearing pool that will assign the costs following the labor of the Service Company employees.

Service: FACILITIES DISTRIBUTION

Description: Facilities costs are assigned or allocated to the functional areas of operating companies and other affiliates who benefit from the use of the facilities. Depending on whether a building is used by one utility company or is a “shared” building, i.e., building used by employees of more than one Operating Company or affiliate, facility costs may include:

Single-utility facility:

The administrative property services labor and non-labor costs, utility expenses, maintenance costs for structures and systems, pro-rated share of property taxes (for owned buildings), and the rent and occupancy expenses (for leased buildings).

Shared facility:

Administrative property services labor and non-labor costs, utilities expenses, and the maintenance costs for structures and systems are captured. If the building is leased, the rent is included. If the building is owned, the carrying costs of the shared assets, such as the depreciation and a return on rate base, are included in the facilities’ cost.

The Property Services department is responsible for the owned and leased facility.

Provider of Service: Service Company or operating companies

User of Service: Service Company, operating companies and affiliates

Method of Allocation: Costs for a single-utility facility are accumulated in the clearing account of the company benefitting from the use of the building, and are then allocated to functional FERC rent accounts based on the most recent quarter’s labor charges.

Costs related to a shared facility, i.e., buildings used by employees of more than one Operating Company or affiliate, are first accumulated in the Service Company clearing account and then distributed to each Operating Company and affiliate based upon the most recent quarter’s labor for the specific employees located in each facility. Once costs are assigned to the appropriate company, they are then allocated to the functional FERC rent accounts based on the most recent quarter’s labor charges.

Service: **MONEY POOL**

Description: Through the Utility Money Pool, temporary surplus funds of Xcel Energy Inc. and the operating companies are available for short-term loans to other operating companies with cash needs.

Provider of Service: Service Company

User of Service: PSCo, NSPM, SPS

Method of Allocation: An operating company can borrow from, and make loans to, the Utility Money Pool, which is administered at cost by the Service Company. In addition, the holding company can deposit surplus funds into the Utility Money Pool. but cannot borrow from the Utility Money Pool. Interest income or expense is charged or credited, as appropriate, to the Utility Money Pool participants.

All charges are directly billed from the Service Company to the appropriate operating company.

NSPM petitioned for and received approval on the use of a utility money pool in Docket No. AI-04-100.

Service: **CUSTOMER BILLING**

Description: NSPM bills customers for electric, gas, propane and miscellaneous nonregulated activities through the customer billing system.

Provider of Service: Operating companies

User of Service: Operating companies, including utility operations, jurisdictions, and nonregulated activities.

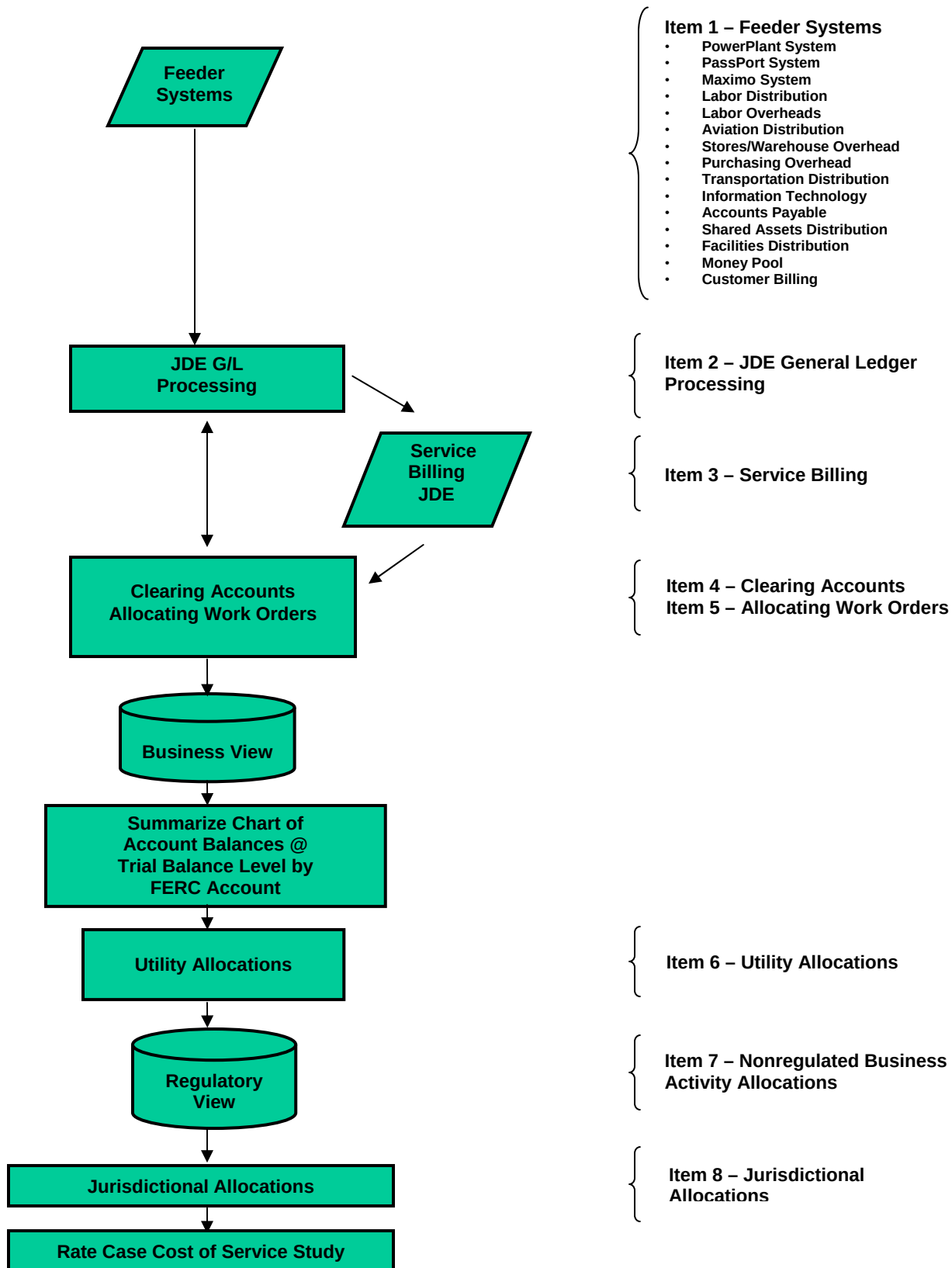
Method of Allocation: Costs related to customer billing are direct charged to specific operating companies whenever possible.

When costs cannot be directly assigned to a specific operating company, they are allocated based on the number of customers' bills.

NSPM Home Smart nonregulated activity that uses the customer billing system is billed and then transferred to the nonregulated activity.

Connect Smart nonregulated activity that uses the customer billing system is billed for services provided based on the number of phone calls which come into the call center and is then reclassified from Service Company regulated activity to non-regulated activity on the books of all Operating Companies.

ADDENDUM A – PROCESS FLOWCHART



VI. ALLOCATING WORKORDERS

OVERVIEW

NSPM's costs are directly assigned or allocated to electric, gas or nonregulated activities whenever possible. An allocating workorder is used to allocate costs to specific FERC accounts based on predefined allocation factors.

ALLOCATIONS

NSPM currently has four allocating workorders. These are as follows:

Compass/Maximo

This workorder is being used to allocate costs associated with the Business Systems' O&M costs for the Energy Supply Maximo system. These costs include information technology application, development and maintenance costs, or system support costs. The allocator is based on the number of Maximo system users. The allocator used in the current year is based on the previous years' actual number of users. The allocation was developed to distribute these costs to production FERC accounts as noted below.

Workorder Number	Allocation Method	Basis for Allocation Selection
12001	Maximo system users	Maximo system users is a reasonable methodology because the operation and maintenance costs associated with the system have a cost causative relationship with the number of users who have access to the system.

The operation and maintenance cost of the Maximo system are allocated to the following FERC accounts:

FERC account 506, Miscellaneous Steam Power Expenses
FERC account 539, Miscellaneous Hydraulic Power Generation Expenses
FERC account 549, Miscellaneous Other Power Generation Expenses

Electric Management System (EMS, also known as Electric SCADA)

This workorder is being used to allocate costs associated with Business Systems' O&M costs for the electric SCADA system. The allocator is based on the number of remote terminal units ("RTU"s). The allocator used in the current year is based on the previous years' actual number of RTUs. The allocation was developed to distribute these costs among production, transmission and distribution FERC accounts as noted below.

Workorder Number	Allocation Method	Basis for Allocation Selection
12004	Number of RTUs	Number of RTUs is a reasonable methodology because the RTUs transmit the data used by the SCADA system.

The operation and maintenance costs of the EMS are allocated to the following FERC accounts:

FERC account 556, System Control and Load Dispatching (Production)
FERC account 561.2, Load Dispatching-Monitor/Operate Transmission System
FERC account 581, Load Dispatching (Distribution)

Gas SCADA

This workorder is being used to allocate costs associated with Business Systems' O&M costs for the gas SCADA system. The allocator is based on gas transmission and distribution plant. The allocation was developed to distribute these costs among transmission and distribution FERC accounts as noted below.

Workorder Number	Allocation Method	Basis for Allocation Selection
12008	Gas Transmission & Distribution Plant	Gas transmission and distribution plant is a reasonable methodology because this system is used to communicate between the control rooms at the plants, transmission and distribution areas.

The operation and maintenance costs of the gas SCADA system are allocated to the following FERC accounts:

FERC account 851, System Control and Load Dispatching (Transmission)
FERC account 871, Distribution Load Dispatching (Gas)

Network Services

This workorder is being used to allocate circuit costs for service centers that primarily benefit electric and gas distribution. The allocator is based on total distribution plant. The allocation was developed to distribute these costs between electric and gas distribution FERC accounts as noted below.

Workorder Number	Allocation Method	Basis for Allocation Selection
12011	Distribution Plant	Distribution plant is a reasonable methodology because these locations primarily benefit electric and gas distribution.

These circuit costs are allocated to the following FERC accounts:

FERC account 588, Miscellaneous Distribution Expenses (Electric)

FERC account 880, Other Expenses (Gas Distribution)

VII. UTILITY ALLOCATIONS

OVERVIEW

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

O&M UTILITY ALLOCATIONS

Introduction

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

Methodology

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

Customer Allocator

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

Revenue Allocator

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

Three-Factor Allocator

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

Labor Allocator

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

RATE BASE AND NON-O&M UTILITY ALLOCATIONS**Introduction**

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

Methodology

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

Three-Factor Allocator

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

Computer Software Study

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

Transportation Study

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

Table A - O&M Utility Allocations

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

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

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

VIII. NONREGULATED ACTIVITY ALLOCATIONS

INTRODUCTION

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

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

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

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

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

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

Evaluation Process

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

Business Profile

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

Direct Charging (Addresses Principle #2)

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

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

Cost Causation Allocations (Addresses Principle #3)

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

Overhead Costs (Addresses Principle #4)

The overhead allocation factors capture indirect costs associated with providing services to nonregulated activities.

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

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

Working Capital Fee (Addresses Principle #3)

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

IX. JURISDICTIONAL ALLOCATIONS

INTRODUCTION

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

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

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

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

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

Direct Assignment Based on FERC Account and Location

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

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

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

Allocation Based on Cost Causal Relationship

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

Electric

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

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

Gas

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

Electric & Gas

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

Allocation Based on a Default Allocator

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

Common and General Plant Investment

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

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

Administrative and General Expenses

When assigning or allocating A&G expenses to jurisdiction, the business area associated with the JDE general ledger account is an additional piece of information used in determining the jurisdiction(s) benefiting from the expenditure. A&G costs for business areas that support the electric production portion of the business, Energy Supply and Nuclear Generation, are allocated to jurisdiction using the twelve-month coincident peak demand allocator. Any Distribution business area A&G costs that cannot be directly assigned to jurisdictions based on the location code are allocated to jurisdiction using the twelve-month end-of-year average customer allocator.

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

Gas A&G expenses are allocated to jurisdiction using the appropriate customer allocation as a default allocator, based on the JDE account location code.

A more detailed description of each allocation type and method of allocation, including examples of why the allocation was chosen to assign costs to jurisdiction is included below.

Table C in this section lists the methodology applied to specific pools of costs.

ALLOCATION METHODS

GAS & ELECTRIC

Allocation: Direct Assigned

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

Allocation: Direct Assigned: State of Minnesota

This allocation type is used for all expenses that are determined to be for the direct benefit or in direct support of the State of Minnesota jurisdiction. The types of costs direct assigned include: direct and indirect assessments related to one of Minnesota's regulatory bodies, Legal Department expense budgeted in support of Minnesota, economic development activities in the State of Minnesota, facilities expenses in support of the Distribution business unit in the state of Minnesota, delivery system operation and maintenance costs in the Metro Area, Northwest and Southeast Regions and Automated Energy System (AES) expenses.

Allocation: Direct Assigned: State of North Dakota

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

Allocation: Direct Assigned: State of South Dakota

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

Allocation: Direct Assigned: Wholesale

This allocation type is used for all expenses that are determined to be for the direct benefit or in direct support of the wholesale full requirements jurisdiction. The types of costs direct assigned include: customer billing expenses budgeted in support of wholesale customers and labor and related expenses in support of wholesale customer metering. Beginning in calendar year 2014, direct assigned wholesale will no longer be used.

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

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

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

This allocation type is used to assign costs to all of Minnesota Company's jurisdictions (Minnesota, North Dakota, and South Dakota) when the work performed benefits all of the company's customers equally. This is the default allocator that is used for the Electric and Gas Distribution, Customer Accounting, Customer Information, Sales and Administrative & General FERC accounts where the general ledger account JDE Business Unit Category Code 6 (Location code) designates support of NSPM Company.

This is also the Gas Utility A&G Corporate Function default allocator type.

Allocation: Customers Year End Average**Minnesota/North Dakota**

This allocation type is used to assign costs to both the North Dakota and Minnesota jurisdictions based on customers in the entire North Dakota Region. This includes customers in Fargo, Moorhead, Grand Forks, East Grand Forks and Minot service areas. This method is the default allocator for O&M expenses associated with general ledger accounts where the JDE business unit category Code 6 (Location code) designates support for Minnesota/North Dakota.

Allocation: Customers Year End Average**Minnesota/South Dakota**

This allocation type is used to assign costs to both the South Dakota and Minnesota jurisdictions based on customers in the entire South Dakota Region. This method is the default allocator for O&M expenses associated with general ledger accounts where the JDE Business Unit Category Code 6 (Location code) designates support for Minnesota/South Dakota.

Allocation: Study Jurisdictional Budget Transmission

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

Allocation: Study Jurisdictional Budget Distribution

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

ELECTRIC UTILITY ONLY

Allocation: Energy

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

Allocation: DemandProd (Coincident Peak)

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

Allocation: DemandTran (Coincident Peak)

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

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

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

GAS UTILITY ONLY

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

Retail revenues include components for the recovery of costs associated with product and delivery of product to the service area. Such costs include capacity or entitlement costs, pipeline transportation costs, commodity costs and costs of alternative gas (propane-air or liquefied natural gas) supplied during times of firm peak demand. Regulations provide for the automatic adjustment of billing rates for price changes and the annual true up of the cost of gas incurred. Demand, Commodity and Purchased Gas Adjustment are components of the Retail Revenues Cost of Gas Recovery study. The portion of total Minnesota Company Cost of Gas included in Retail Revenues that the Minnesota jurisdiction represents is also applied to total Minnesota Company Cost of Gas expense accounts to achieve revenue neutrality for revenue requirements consideration.

Allocation: Design Demand Day

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

Allocation: Load Dispatch

Expressed as a percentage, Load Dispatch is a combination of the Minnesota jurisdiction Design Demand Day and the Minnesota jurisdiction total Retail sales and Transportation throughput each weighted equally.

Allocation: Limited Firm and Standby Services Study

Expressed as a percentage, Limited Firm and Standby services, in revenues, is the ratio of Minnesota jurisdiction availability charges and volumetric charges to the total Minnesota Company; in costs, it is the ratio of Minnesota jurisdiction volumetric product costs to the total Minnesota Company program product costs.

Table C

Allocation to Jurisdiction							
Selection Criteria *							
Sub-Business Unit (CC2)	Plant Function	Functional Class ID / Description	Location (CC6)	Functional Use	Utility	Jurisdiction	Allocation Methodology
Budget							
Production	Production	1 / Electric Steam Production Plant			Electric	MN/ND/SD / WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	2 / Electric Nuclear Production Plant			Electric	MN/ND/SD / WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	3 / Electric Hydro Production Plant			Electric	MN/ND/SD / WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	4 / Electric Other Production Plant			Electric	MN/ND/SD / WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	4 / Electric Other Production Plant-Wind			Electric	MN/ND/SD / WHSL	Electric - Energy
Production	Production	22 / Nuclear Fuel			Electric	MN/ND/SD / WHSL	Electric - Demand Prod (Coincident Peak)
Production	Common & General	24 / Electric Intangible Plant			Electric	MN/ND/SD / WHSL	Electric - Demand Prod (Coincident Peak)
Production	Common & General	26 / Common Intangible Plant			Electric	MN/ND/SD / WHSL	Electric - Demand Prod (Coincident Peak)
Production	Common & General	29 / Electric General Plant			Electric	MN/ND/SD / WHSL	Electric - Demand Prod (Coincident Peak)
Production	Common & General	31 / Common General Plant			Electric	MN/ND/SD / WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	23 / Decommissioning	FERC MN		Electric	MN/ND/SD / WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	23 / Decommissioning	Minnesota		Electric	MN	Direct Assigned - State of Minnesota
Production	Production	23 / Decommissioning	North Dakota		Electric	ND	Direct Assigned - State of North Dakota
Production	Production	23 / Decommissioning	South Dakota		Electric	SD	Direct Assigned - State of South Dakota
Production	Production	23 / Decommissioning	Wisconsin		Electric	WI	Direct Assigned - Wisconsin
Electric Transmission	Transmission	5 / Electric Transmission Plant			Electric	MN/ND/SD / WHSL	Electric - Demand Tran (Coincident Peak)
Electric Transmission	Transmission	5 / Transmission Direct Assignment	Minnesota	DRCT	Electric	MN	Direct Assigned - State of Minnesota
Electric Distribution	Transmission	5 / Transmission Serving Distribution	Minnesota		Electric	MN	Direct Assigned - State of Minnesota
Electric Distribution	Transmission	5 / Transmission Serving Distribution	North Dakota		Electric	ND	Direct Assigned - State of North Dakota
Electric Distribution	Transmission	5 / Transmission Serving Distribution	South Dakota		Electric	SD	Direct Assigned - State of South Dakota
Production	Transmission	5 / Transmission Generation Step-up		BSLD, PEAK	Electric	MN/ND/SD / WHSL	Electric - Demand Prod (Coincident Peak)
Electric Transmission	Common & General	24 / Electric Intangible Plant			Electric	MN/ND/SD / WHSL	Electric - Demand Tran (Coincident Peak)
Electric Transmission	Common & General	26 / Common Intangible Plant			Electric	MN/ND/SD / WHSL	Electric - Demand Tran (Coincident Peak)

Selection Criteria *							
Sub-Business Unit (CC2)	Plant Function	Functional Class ID / Description	Location (CC6)	Functional Use	Utility	Jurisdiction	Allocation Methodology
Budget							
Electric Transmission	Common & General	29 / Electric General Plant			Electric	MN/ND/SD / WHSL	Electric - Demand Tran (Coincident Peak)
Electric Transmission	Common & General	31 / Common General Plant			Electric	MN/ND/SD / WHSL	Electric - Demand Tran (Coincident Peak)
Electric Distribution	Distribution	6 / Electric Distribution Plant	Minnesota		Electric	MN	Direct Assigned - State of Minnesota
Electric Distribution	Distribution	6 / Electric Distribution Plant	North Dakota		Electric	ND	Direct Assigned - State of North Dakota
Electric Distribution	Distribution	6 / Electric Distribution Plant	South Dakota		Electric	SD	Direct Assigned - State of South Dakota
Electric Distribution	Distribution	6 / Electric Distribution Plant	Wholesale		Electric	WHSL	Direct Assigned - Wholesale Full Requirements
Production	Distribution	6 / Distribution Generation Step-up		PEAK	Electric	MN/ND/SD / WHSL	Electric - Demand Prod (Coincident Peak)
Electric Transmission	Distribution	6 / Distribution Serving Transmission		TBULK	Electric	MN/ND/SD / WHSL	Electric - Demand Tran (Coincident Peak)
Electric Distribution	Common & General	24 / Electric Intangible Plant			Electric	MN/ND/SD / WHSL	Customer Year End Average - Electric Minnesota Company MN/ND/SD/WHSL
Electric Distribution	Common & General	26 / Common Intangible Plant			Electric	MN/ND/SD / WHSL	Customer Year End Average - Electric Minnesota Company MN/ND/SD/WHSL
Electric Distribution	Common & General	29 / Electric General Plant			Electric	MN/ND/SD / WHSL	Customer Year End Average - Electric Minnesota Company MN/ND/SD/WHSL
Electric Distribution	Common & General	31 / Common General Plant			Electric	MN/ND/SD / WHSL	Customer Year End Average - Electric Minnesota Company MN/ND/SD/WHSL
Gas	Production	7 / Gas Manufactured Production Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Storage	9 / Gas Underground Storage Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Transmission	10 / Gas Transmission Plant			Gas	MN	Direct Assigned - State Of Minnesota
Gas	Transmission	10 / Gas Transmission Plant			Gas	ND	Direct Assigned - State of North Dakota
Gas	Distribution	11 / Gas Distribution Plant			Gas	MN	Direct Assigned - State of Minnesota
Gas	Distribution	11 / Gas Distribution Plant			Gas	ND	Direct Assigned - State of North Dakota
Gas	Common & General	25 / Gas Intangible Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Common & General	26 / Common Intangible Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Common & General	30 / Gas General Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Common & General	31 / Common General Plant			Gas	MN/ND	Gas - Design Demand Day

Selection Criteria *							
Sub-Business Unit (CC2)	Plant Function	Functional Class ID / Description	Location (CC6)	Functional Use	Utility	Jurisdiction	Allocation Methodology
Budget							
Gas	Common & General	25 / Gas Intangible Plant			Gas	MN/ND	Customer Year End Average - Gas Minnesota Company MN/ND
Gas	Common & General	26 / Common Intangible Plant			Gas	MN/ND	Customer Year End Average - Gas Minnesota Company MN/ND
Gas	Common & General	30 / Gas General Plant			Gas	MN/ND	Customer Year End Average - Gas Minnesota Company MN/ND
Gas	Common & General	31 / Common General Plant			Gas	MN/ND	Customer Year End Average - Gas Minnesota Company MN/ND
Gas	Common & General	34 / Gas Other Storage Plant			Gas	MN/ND	Gas - Design Demand Day

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

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Work Order No.	Work Order Title	Description of Services Provided	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent 2016
110	Executive - Corporate Governance	Executive - Corporate Governance includes the labor and non-labor costs for executive corporate management, long-term business strategy development and other programs that ensure the continuity and development of management. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc. This is primarily used by the Chief Executive Officer, Chief Operating Officer, Chief Administrative Officer, the Corporate Secretary and the Aviation department.	Asset/Revenue/Number of Employees	Executive - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Number of employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	40.4599%
114	Board of Directors - Corporate Governance	Board of Directors - Corporate Governance includes the labor and non-labor costs related to the Board of Directors (BOD). BOD costs may include Directors fees, retirement expenses and replacement fees; Board/Committee meetings and BOD related consulting. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc. This allocator is primarily used by the Corporate Secretary/Shareholder Relations department.	Asset/Revenue/Number of Employees	Board of Directors - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Number of employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	40.4599%
115	Shareholder - Corporate Governance	Shareholder - Corporate Governance includes the labor and non-labor costs for serving as liaison between Xcel Energy BOD and the shareholders, manages employee/executive stock award matters, liaison between Xcel Energy and the proxy advisory group, monitoring stock ownership patterns, planning shareholder meetings, coordinating the transfer agent and shareholder record keeping functions. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc. This allocator is primarily used by the Corporate Secretary/Shareholder Relations department.	Asset/Revenue/Number of Employees	Shareholder - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Number of employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	40.4599%
116	Investor Relations - Corporate Governance	Investor Relations - Corporate Governance includes the labor and non-labor costs for communications to investors and the financial community, providing management with feedback from investors, assisting in the communication to investors of debt and equity securities issuances, assists in the development of presentations for Board of Directors, develops and delivers Xcel Energy's credit story to credit rating agencies, develops and presents Xcel Energy's investment story to investors, reviews all public financial documents for accuracy and completeness and distributes all financial releases. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc. This allocator is primarily used by the Investor Relations area.	Asset/Revenue/Number of Employees	Investor Relations - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Number of employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	40.4599%
120	Accounting, Reporting, & Taxes	Accounting, Reporting & Taxes services includes the labor and non-labor costs for preparation of operating and non-operating financial statements, tax returns and reporting, performing accounting for the employee benefit plans, ensuring compliance with applicable laws and regulations of the operating and non-operating companies; composing the corporate wide regulatory accounting policy, and coordinating the budgeting process with the operating and non-operating companies. This is primarily used by departments that fall under the Controller such as Tax Services, Capital Asset Accounting, Regulatory Accounting, Commercial Accounting, and Corporate Budgeting.	Asset/Revenue/Number of Employees	Accounting Reporting & Taxes services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	45.0621%

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Work Order No.	Work Order Title	Description of Services Provided	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent 2016
121	Accounting & Reporting - Corporate Governance	Accounting & Reporting - Corporate Governance includes the labor and non-labor costs associated with preparing and filing consolidated reporting and financial statements, preparing consolidated budgets, completing the consolidation process, maintaining the books and records of Xcel Energy Inc. and Service Company, composing the corporate-wide regulatory accounting policy and compliance, Sarbanes-Oxley (SOX) documentation and compliance, and Chief Financial Officer activities related to the Audit Committee. Provides financial leadership to Xcel Energy and provides policies, controls, and leadership to the Financial Operations business area. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc. This is primarily used by the CFO as well as departments that fall under the Controller such as Capital Asset Accounting, Regulatory Accounting, Commercial Accounting, and Corporate Budgeting.	Asset/Revenue/Number of Employees	Accounting & Reporting - Corporate Governance -The three-factor formula reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporate and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Number of employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	40.4599%
123	Accounting - Operating Companies	Accounting - Operating Companies includes the labor and non-labor costs associated with operating company revenue accounting, budgeting, regulatory reporting, sales and use taxes, business area support for utility areas, operating company budgeting support, and capital asset accounting. This is primarily used by departments that fall under the Controller such as Capital Asset Accounting, Regulatory Accounting, Commercial Accounting, and Corporate Budgeting.	Asset/Revenue/Number of Employees	Accounting - Operating Companies services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	45.0776%
125	Acctg, Rptg, Tax - MN, WI	Acctg, Rptg, Tax - MN, WI includes the labor and non-labor costs associated with NSPM & NSPW revenue accounting, budgeting, regulatory reporting, sales and use taxes, business area support for utility areas, operating company budgeting support, and capital asset accounting. This is primarily used by departments that fall under the Controller such as Capital Asset Accounting, Regulatory Accounting, Commercial Accounting, and Corporate Budgeting.	Asset/Revenue/Number of Employees	Acctg, Rptg, Tax - MN, WI services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to NSPM & NSPW who benefit from the services.	87.3597%
126	Acctg, Rptg, Tax - MN, WI Elec	Acctg, Rptg, Tax - MN, WI Elec Electric includes the labor and non-labor costs associated specifically with NSPM & NSPW Electric utility revenue accounting, budgeting, regulatory reporting, sales and use taxes, business area support for utility areas, operating company budgeting support, and capital asset accounting. This is primarily used by departments that fall under the Controller such as Capital Asset Accounting, Regulatory Accounting, Commercial Accounting, and Corporate Budgeting.	Asset/Revenue/Number of Employees	Acctg, Rptg, Tax - MN, WI Elec services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to NSPM & NSPW electric utility who benefit from the services.	87.3597%
127	Acctg, Rptg, Tax - OpCos Elec	Acctg, Rptg, Tax - OpCos Elec includes the labor and non-labor costs associated specifically with operating company electric utility revenue accounting, budgeting, regulatory reporting, sales and use taxes, business area support for utility areas, operating company budgeting support, and capital asset accounting. This is primarily used by departments that fall under the Controller such as Capital Asset Accounting, Regulatory Accounting, Commercial Accounting, and Corporate Budgeting.	Asset/Revenue/Number of Employees	Acctg, Rptg, Tax - OpCos Elec services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies electric utility who benefit from the services.	45.0776%
128	Prop Trading - Back Office	Prop Trading - Back Office includes the labor and non-labor costs associated with the accounting support and vice president oversight of proprietary trading activities for Northern States Power Minnesota, Public Service Company of Colorado and Southwestern Public Service Company.	Joint Operating Agreement Peak Hour Megawatt Load Ratio	This allocation is based on the Peak Hour Megawatt Load Ratio for the previous year. These are reported by Megawatt. This follows the JOA which states that the "Non-System Marketing Net Revenue shall be allocated among the Operating Companies in proportion to the prior year's annual peak load of each Operating Company".	42.1976%
129	Gen/Prop Trading - Back Office	Gen/Prop Trading - Back Office includes the labor and non-labor costs associated with oversight and administration of accounting related trading costs including proprietary and generation trading for Northern States Power Minnesota, Northern States Power Wisconsin Public Service Company of Colorado and Southwestern Public Service Company.	Joint Operating Agreement Labor Hours Ratio	Gen/Prop Trading - Back Office uses a labor hour allocation based on Commercial Operations front office Generation (purchase and sales) and proprietary trading activities. Is reasonable because there is a direct correlation between the front office activities and the mid-office and back-office activities. It is required to use the Joint Operating Agreement for the Proprietary split for these accounting and trading costs.	26.2401%
130	Audit Services	Audit Services includes the labor and non-labor costs for auditing operating and non-operating companies, evaluating and improving risk management, ethical conduct and the implementation of best practices for operating and non-operating companies, conducting financial operations and information system audits, performing audits and reviews for compliance with regulatory and legal requirements and contracts with vendors and other parties; establishing and reviewing internal controls for operating and non-operating companies, establishing and reviewing SOX compliance requirements/control testing and evaluating contract risks for the operating and non-operating companies. This is primarily used by the Audit Services department.	Asset/Revenue/Number of Employees	Audit Services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	45.0621%

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Work Order No.	Work Order Title	Description of Services Provided	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent 2016
131	Audit Services - Corporate Governance	Audit Services Corporate Governance includes the labor and non-labor costs associated with the financial operations and information system audits of the holding company and service company; evaluating and improving risk management, corporate internal control guidelines and procedures; ethical conduct and the implementation of best practices, reviewing financial reporting requirements and controls under Sarbanes-Oxley legislative requirements, auditing of consolidated financial statements and activities related to the Audit Committee, performing audits and reviews for compliance with regulatory and legal requirements on contracts with vendors and other parties, providing consulting services to management for operational and process improvement reviews, assistance in internal investigations of fraud, administering the corporate compliance hotline, conflict of interest investigations, or other potential violations of the Xcel Energy Code of Conduct. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc. This is primarily used by the Audit Services department.	Asset/Revenue/Number of Employees	Audit Services - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Number of employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	40.4599%
132	Audit Services - OpCos	Audit Services - OpCos includes the labor and non-labor costs for auditing operating companies, evaluating and improving risk management, ethical conduct and the implementation of best practices for operating companies, conducting financial operations and information system audits, performing audits and reviews for compliance with regulatory and legal requirements and contracts with vendors and other parties; establishing and reviewing internal controls for operating companies, establishing and reviewing SOX compliance requirements/control testing and evaluating contract risks for the operating companies. This is primarily used by the Audit Services department.	Asset/Revenue/Number of Employees	Audit Services - OpCos services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	45.0776%
133	Audit Services - OpCos - Elect	Audit Services - OpCos - Elect includes the labor and non-labor costs for auditing operating companies electric utility, evaluating and improving risk management, ethical conduct and the implementation of best practices for operating companies electric utility, conducting financial operations and information system audits, performing audits and reviews for compliance with regulatory and legal requirements and contracts with vendors and other parties; establishing and reviewing internal controls for operating companies electric utility, establishing and reviewing SOX compliance requirements/control testing and evaluating contract risks for the operating companies electric utility. This is primarily used by the Audit Services department.	Asset/Revenue/Number of Employees	Audit Services - OpCos - Elect services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies electric utility who benefit from the services.	45.0776%
134	Audit Services - OpCos - Gas	AUDIT OpCos Gas includes the labor and non-labor costs for auditing operating companies gas utility, evaluating and improving risk management, ethical conduct and the implementation of best practices for operating companies gas utility, conducting financial operations and information system audits, performing audits and reviews for compliance with regulatory and legal requirements and contracts with vendors and other parties; establishing and reviewing internal controls for operating companies gas utility, establishing and reviewing SOX compliance requirements/control testing and evaluating contract risks for the operating companies gas utility. This is primarily used by the Audit Services department.	Asset/Revenue/Number of Employees	Audit Services - OpCos - Gas services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies gas utility who benefit from the services.	52.4080%
135	Capital Asset Acctg	Capital Asset Acctg includes the labor and non-labor costs associated with operating and non-operating company capital asset accounting, budgeting, regulatory reporting, business area support for utility areas, and operating company budgeting support. This is primarily used by Capital Asset Accounting.	Asset/Revenue/Number of Employees	Capital Asset Acctg services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.9211%
140	Finance & Treasury	Finance & Treasury services includes the labor and non-labor costs related to equity and debt securities issuance, cash management, relationships with financial institutions, compliance with debt covenants, Service Company portion of General and Excess liability insurance, and management of the Pension Fund and 401k benefits for operating companies. This is primarily used by the Treasurer's organization.	Asset/Revenue/Number of Employees	Finance & Treasury services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	45.0621%
141	Finance & Treasury - Corporate Governance	Finance & Treasury - Corporate Governance includes the labor and non-labor costs related to equity and debt securities issuance, relationships with financial institutions, cash management, investing activities and monitoring the capital markets, holding company commercial paper transactions, compliance with debt covenants, corporate-wide protection of assets from catastrophic loss using risk financing mechanisms including captive risk retention and design and negotiation of insurance contracts with commercial and industry mutual underwriters (Service Company portion of Auto Liability, Cyber, and various other insurance policies), supervising the asset management firms for the Pension Fund and 401k benefits. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc. This is primarily used by the Treasurer's organization.	Asset/Revenue/Number of Employees	Finance & Treasury - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Number of employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	40.4599%

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142	Risk Management	Risk Management develops and negotiates security agreements with counterparties; reviews high-risk vendor creditworthiness for the Environmental Services group; supports wind generation, solar carbon offsets, emission allowances, bundled energy and RECs, biomass and other renewable energy purchase agreements; participates in industry contracts working groups; representing Xcel Energy operating utilities; performs production cost modeling and analysis for corporate budgeting; analyzing value and risks of structured purchases and generation system modifications; performs long range system modeling to evaluate large capacity acquisition alternatives; provides central coordination of annual capital funding process for Distribution and maintains and administers the Risk Registry database, evaluate and prioritizes specific risk mitigations for distribution assets; develops strategies for distribution infrastructure including building and implementing stochastic models for asset life-cycle analysis and other ad hoc asset specific requests; creates retail and system load and energy forecasts providing regular updates to senior management and analyses of key drivers; provides data support and analyses for financial disclosures; and provides analyses and reporting of current sales and peak demand levels relative to forecasts. This is primarily used by the Risk Management organization.	Asset/Revenue/Number of Employees	Risk Management services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	45.0621%
143	Risk Management - Corporate Governance	Risk Management Corporate Governance includes the labor and non-labor costs of providing administration of the Transaction Review Committee which handles contract and deal approvals for Commercial Operations, Resource Planning and Energy Supply, provides analysis associated with key risks facing Xcel Energy Inc., negotiates and manages required security (e.g., bank letters of credit, bonds and guarantees among others); reviews and approves all documents requiring Contracts area sign-off. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc. This is primarily used by the Risk Management area.	Asset/Revenue/Number of Employees	Risk Management - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Number of employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	40.4599%
144	Prop Trading - Frt/Mid Office	Prop Trading - Frt/Mid Office includes the labor and non-labor costs associated with proprietary trading activities which are short term transactions undertaken in the wholesale electric markets where electricity is purchased for the purpose of selling it. Also included are supporting activities: evaluating the credit worthiness of counterparties, reviewing contracts to ensure that regulations are being complied with, evaluating profitability and appropriateness of trades to ensure they are in the best interest of shareholders and rate payers, and ensuring that trades identified as proprietary appropriately fall into that category. This allocator is primarily used by Financial Operations' Risk Management and Energy Supply's Commercial Operations.	Joint Operating Agreement Peak Hour Megawatt Load Ratio	This allocation is based on the Peak Hour Megawatt Load Ratio for the previous year. These are reported by Megawatt. This follows the JOA which states that the "Non-System Marketing Net Revenue shall be allocated among the Operating Companies in proportion to the prior year's annual peak load of each Operating Company".	42.1976%
145	Gen/Prop Trading - Mid Office	Gen/Prop Trading - Mid Office includes the labor and non-labor costs associated with independent evaluation and risk measurement of trading and generation book transactions including preparing daily P&L (profit and loss) reports and individual trader profit and loss reports for the prop book, daily generation book valuation reports for each system showing a net fuel positions and any forward sales values and/or hedges, ensuring that margin reporting follows all SEC rules and GAAP reporting and that credit and risk policies and procedures are complied with.	Joint Operating Agreement Labor Hours Ratio	Gen/Prop Trading - Back Office uses a labor hour allocation based on Commercial Operations front office Generation (purchase and sales) and proprietary trading activities. It is reasonable because there is a direct correlation between the front office activities and the mid-office and back-office activities. It is required to use the Joint Operating Agreement for the Proprietary split for these accounting and trading costs.	28.7745%
146	Risk Mgmt - OpCos	Risk Mgmt - OpCos includes the labor and non-labor costs of oversight and administrative of operating company risk management work, working with counterparties to establish enabling agreements with operating companies, risk management reports including all operating companies (such as CDAD - Contract Development, Approval & Delegation or TRC- Transaction Review Committee Reporting).	Asset/Revenue/Number of Employees	Risk Mgmt - OpCos services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	45.0776%
147	Captive Insurance	Captive Insurance - The Property Loss Control Engineers services includes the labor and non-labor costs for each primary Operating Company(s) (OpCos) as well as all of Energy Supply Services. Having an expertise in an area, they lend support to each other and members of Energy Supply, and the Utilities Group, throughout the corporation. Fire Protection, Transformer Maintenance, Turbine Characteristics, Policies and Procedures are some of the areas in which expertise has been developed. This expertise is then shared on a regular basis to the benefit of all OpCos and it is further shared at periodic Engineering meetings hosted by Hazard Insurance, which bring together Engineers from the OpCos, the Property Loss Control Engineers and Insurance Company representatives to promote Loss Control.	Asset/Revenue/Number of Employees	Captive Insurance - OpCos services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	45.0776%

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161	Corporate Strategy & Bus Dev - Corporate Governance	Corporate Strategy & Business Development - Corporate Governance includes the labor and non-labor costs associated with providing leadership for the implementation of company-wide business strategies and plans; portfolio management including the evaluation of potential opportunities for mergers, acquisitions and divestitures; providing financial, analytical and reporting support; researching and providing business intelligence information. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc. This allocator is primarily used by the Portfolio Strategy area.	Asset/Revenue/Number of Employees	Corporate Strategy & Bus Dev - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Number of employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	40.4599%
162	Corp Strategy & Bus Dev - OpCo	Corp Strategy & Bus Dev - OpCo services includes the labor and non-labor costs associated with studying developing and demonstrating new energy technologies for future utility uses, providing operating company strategy and planning support, and providing leadership for Xcel Energy's renewable energy strategy and business development. This allocator is primarily used by the Portfolio Strategy business area.	Asset/Revenue/Number of Employees	Corp Strategy & Bus Dev - OpCo services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	45.0776%
163	LEGAL OPCo Electric	LEGAL OPCo Electric services includes the labor and non-labor costs for operating companies electric utility legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts. This is primarily used by the General Counsel area.	Asset/Revenue/Number of Employees	LEGAL OPCo Electric services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies electric utility who benefit from the services.	45.0776%
164	Legal OPCo Gas	Legal OPCo Gas NSPM, NSPW and PSCO Gas services includes the labor and non-labor costs for operating companies gas utility legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts. This is primarily used by the General Counsel area.	Asset/Revenue/Number of Employees	Legal - OPCos Gas services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	52.4080%
170	Legal	Legal services includes the labor and non-labor costs for operating and non-operating legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts. This is primarily used by the General Counsel area.	Asset/Revenue/Number of Employees	Legal services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	45.0621%
171	Legal - Corporate Governance	Legal services Corporate Governance includes the labor and non-labor costs for anticipating and fulfilling the legal needs of Xcel Energy, its Board of Directors, officers, legal entities, business areas and corporate operations to protect the company's assets and to minimize potential liability. Provides services related to labor and employment law pertaining to Service Company employees, litigation, contracts, rates and regulation, environmental matters and other legal matters. Supports Xcel Energy and its subsidiaries in fulfilling corporate and business area strategies ranging from maintaining/improving regulatory relationships to continued leadership on environmental issues. Corporate governance activities are general services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc. This allocator is primarily used by the General Counsel area.	Asset/Revenue/Number of Employees	Legal - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Number of employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	40.4599%
172	Legal - NSPM & NSPW	Legal - NSPM & NSPW services includes the labor and non-labor costs for NSPM & NSPW operating companies legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts. This is primarily used by the General Counsel area.	Asset/Revenue/Number of Employees	Legal - NSPM & NSPW services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to NSPM & NSPW who benefit from the services.	87.3597%
173	Legal - NSPM & NSPW Electric	Legal - NSPM & NSPW Electric services includes the labor and non-labor costs for NSPM & NSPW operating companies electric legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts. This is primarily used by the General Counsel area.	Asset/Revenue/Number of Employees	Legal - NSPM & NSPW services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to NSPM & NSPW electric utility who benefit from the services.	87.3597%
174	Legal - OpCos	Legal - OpCos services includes the labor and non-labor costs for operating companies legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts. This is primarily used by the General Counsel area.	Asset/Revenue/Number of Employees	Legal - OpCos services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	45.0776%

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180	Communications - Corporate Governance	Communications - Corporate Governance includes the labor and non-labor costs to assist and ensure Executive Management, Investor Relations and others communicate appropriately with shareholders, the public, and other key stakeholder audiences. Key projects include: development and production of the annual report and other communications to investors; speeches, videos, and major presentations delivered by top executives; and speeches, displays, video and presentations for the company's annual meeting of shareholders. Media Relations contributes to building Xcel Energy's reputation by developing media and public relations strategies for major company initiatives and issues; responding to news media inquiries; working pro-actively with the media to forward story ideas and information about company events, policies and actions, and providing media training for company spokespersons. Media Relations also plays a key role in crisis communications and emergency preparedness efforts. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc. This allocator is primarily used by the Corporate Communications area.	Asset/Revenue/Number of Employees	Communications - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Number of employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	40.4599%
181	Employee Communications	Employee Communications includes the labor and non-labor costs for the development and enhancement of employee awareness and understanding of the company's strategies, priorities, decisions and performance objectives. It develops and produces regular communication vehicles, including TODAY (daily news bulletin on intranet); XTRA (monthly print publication for all employees and retirees); All Managers E-mail (real-time communication for employees who supervise and manage others); Focus on Financials for a employees; targeted communications for specific business areas, such as Human Resources, and employee meetings. This is primarily used by the Corporate Communications area.	Number of Employees	Employee Communications using Number of Employees to allocate costs is reasonable because the costs are directly related to employees.	50.2642%
182	Xcel Foundation	Xcel Foundation services includes the labor and non-labor costs associated with the management and administration of the Xcel Energy Foundation. This is primarily used by the Corporate Communications area which manages the Xcel Energy Foundation.	Asset/Revenue/Number of Employees	Xcel Foundation services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	40.5122%
184	Branding	Branding services includes the labor and non-labor costs for brand advertising and management of community affairs programs such as employee volunteerism, educational programs and community events, the company's investment in major sponsorships such as the Xcel Energy Center as well as ensuring that such sponsorships and related activities support the company's brand, mission and values. This allocator is primarily used by the Corporate Communications area.	Asset/Revenue/Number of Employees	Branding services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	40.5122%
185	Customer Safety Advertising/Information Costs	Customer Safety Advertising and Information costs services includes the labor and non-labor costs associated with public safety advertising, information and education. This is used by the Corporate Communications and Safety organizations.	Number of Customers	Customer Safety Advertising/Information Costs using number of customers to allocate costs is reasonable because the costs are directly related to customers.	35.5399%
189	Human Resources (HR) - Corporate Governance	HR services Corporate Governance includes the labor and non-labor costs for executive officers' and Service Company employees' compensation plans, corporate HR policies, executive policy benefit plans, payroll services for Service Company and the employees' handbook. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc. This is primarily used by the Human Resources and Safety organizations.	Asset/Revenue/Number of Employees	Human Resources (HR) - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Number of employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	40.4599%
190	Human Resources (Diversity/Safety/Emp Relations)	HR-Diversity/Safety/Employee Relations includes the labor and non-labor costs for work performed for operating and affiliate company employees, such as diversity programs, providing workforce relations resources for labor agreements, arbitration, and training. Manage, design, and implement Corporate Safety initiatives. This is primarily used by the Human Resources and Safety organizations.	Number of Employees	Human Resources (Diversity/Safety/Emp Relations) using number of employees to allocate HR costs is reasonable because the costs are directly related to employees.	50.3402%
197	Human Resources - Operating Companies	HR-Operating Companies services includes the labor and non-labor costs for work performed for operating and affiliate company employees such as diversity programs, providing workforce relations resources and labor agreements, design and implement Corporate Safety initiatives, provide online training and open enrollment classes, provide individual and team development, coaching and employee engagement, provide strategic and tactical consulting on HR strategies and planning. This is primarily used by the Human Resources and Safety organizations.	Number of Employees	Human Resources - Operating Companies using number of employees to allocate costs is reasonable because the costs are directly related to employees.	50.3402%

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198	Payroll	Payroll services include the labor and non-labor costs for processing payroll including consolidation of time collection, calculation of salaries and wages, administration of employee deductions, account distribution and reconciliation, allocation and accounting for employment taxes and compliance reports. This is primarily used by the Human Resources area.	Number of Employees	Payroll using number of employees to allocate costs is reasonable because the costs are directly related to employees.	50.2642%
199	Human Resources - Recruitment	HR-Recruitment services includes the labor and non-labor costs for work performed for operating and affiliate company employees such as employee recruitment, staffing administration for non-bargaining positions and provides Affirmative Action plans (development) and government audit management (compliance). This is primarily used by the Human Resources area.	Number of Employees	Human Resources - Recruitment using number of employees to allocate costs is reasonable because the costs are directly related to employees.	50.3402%
403	Customer Service IT - FERC 903	Customer Service Information Technology (IT) FERC 903 services includes the labor and non-labor costs for IT applications related customer billing to customers, call center support and credit and collections. This is primarily used by the Business Systems area.	Number of Customers	Customer Service IT - FERC 903 using number of customers to allocate costs is reasonable because the costs are directly related to customers.	35.5399%
405	Customer Service IT FERC 903 - North	Customer Service IT FERC 903 - North services includes the labor and non-labor costs for IT applications related customer billing to customers, call center support and credit and collections. This allocation is used when Northern States Power Company-Minnesota and Northern States Power Company-Wisconsin are the only companies benefiting from the services. This is primarily used by the Business Systems area.	Number of Customers	Customer Service IT FERC 903 - North using number of customers to allocate costs is reasonable because the costs are directly related to customers.	84.0832%
409	Federal Lobbying	Federal Lobbying services includes the labor and non-labor costs for federal and state lobbying activities and the federal Political Action Committee (PAC). This is primarily used by the Federal and State Affairs organization.	Asset/Revenue/Number of Employees	Federal Lobbying services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are provided to a subset of companies based on who benefits from the services. These costs are recorded in FERC 426.4.	40.5584%
410	Governmental Affairs	Governmental Affairs includes the labor and non-labor costs associated with the interpretation of laws, regulations and environmental policy to ensure compliance and cost effectiveness for Xcel Energy customers and stockholders Internal legislative policy development and issues management, appraise management and internal customers of political and policy trends and developments, develop and maintain relationships with regulatory officials and staff. This is primarily used by Federal and State Affairs and the Environmental areas.	Asset/Revenue/Number of Employees	Governmental Affairs services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	40.5584%
412	Marketing & Sales	Marketing & Sales services includes the labor and non-labor costs for marketing and sales services for the operating companies for their customers including strategic planning, segment identification, business analysis, sales planning, customer service, promoting products to the business market, and providing regulatory and policy support with respect to utility Energy Efficiency and Demand Response program design, evaluation, measurement and verification, cost effectiveness testing, and cost recovery. This is primarily used by the Marketing area.	Revenue	Marketing & Sales using Revenue to allocate costs is reasonable because Marketing & Sales support the revenue-producing operations of the company.	41.1362%
413	Payment and Reporting	Payment & Reporting services includes the labor and non-labor costs associated with processing payments to vendors, providing audit research and reconciliation support for Accounts Payable transactions, preparing statistical and 1099 reporting, and administering the purchase card programs. This is primarily used by the Supply Chain organization.	Invoice Transactions	Payment and Reporting using invoice transactions to allocate costs is reasonable because the costs are directly related to the number of invoices processed.	34.1956%
414	Energy Supply Business Resources	Energy Supply Business Resources services includes the labor and non-labor costs of performance analysis, specialists and analytical services provided to the operating companies' generation facilities. This is primarily used by Business Systems and Energy Supply areas.	MWH Generation	Energy Supply Business Resources using MWH generation to allocate costs is reasonable because the costs are directly related to the support of the power plants.	32.1734%
415	Energy Markets - Fuel	Energy Markets Fuel includes the labor and non-labor costs for planning and implementing power supply portfolios to provide reliable service to native load and to capitalize on market opportunities including purchasing fuel for the operating companies' electric generation system (excluding nuclear) and resource planning and acquisition including purchase power and account management. This is primarily used by the Energy Supply area.	MWH Generation	Energy Markets - Fuel using MWH generation to allocate costs is reasonable because the costs are directly related to the purchase of fuel for generation.	32.1734%
416	Supply Chain	Supply Chain includes the labor and non-labor costs for operating companies diversity program expenses as well as various dues for specific sponsored agencies (Chamber of Commerce, social service dues, etc.)	Asset/Revenue/Number of Employees	Supply chain services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	45.0776%
417	Rates & Regulation	Rates & Regulation includes the labor and non-labor costs for determining the regulated utilities' revenue requirements and rates for electric and gas customers regulatory strategy coordinating the regulatory compliance requirements, establishing and maintaining relationships with regulatory bodies, policy development of regulatory and legislative strategy preparing and organizing rate case filings. This is primarily used by the Regulatory & Resource Planning area.	Revenue	Rates & Regulation using revenue to allocate costs is reasonable because they are responsible for setting revenue requirements.	41.1356%
418	Rates & Regulation - Electric	Rates & Regulation - Electric includes the labor and non-labor costs for determining the regulated utilities' electric utility revenue requirements and rates for electric customers regulatory strategy, coordinating the regulatory compliance requirements, establishing and maintaining relationships with regulatory bodies, policy development of regulatory and legislative strategy, preparing and organizing rate case filings. This is primarily used by the Regulatory & Resource Planning area.	Revenue	Rates & Regulation - Electric using revenue to allocate costs is reasonable because they are responsible for setting revenue requirements.	41.1362%

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423	Customer & Field Operations Constr, Oper & Maint	Customer & Field Operations Constr, Oper & Maint services includes the labor and non-labor costs for the construction, operations and maintenance of transmission and delivery systems. This is primarily used by the Transmission and Substations area.	Electric Transmission Plant/ Electric Distribution Plant/ Gas Transmission Plant/Gas Distribution Plant	Customer & Field Operations Constr, Oper & Maint using delivery gross plant to allocate costs is reasonable because these costs are directly related to the electric and gas delivery systems.	35.5340%
429	Energy Markets - Regulated Trading (Gen Book)	Energy Markets Regulated Trading services includes the labor and non-labor costs of providing electric trading services to the operating companies' electric generation systems, including load management, system optimization and origination. This is primarily used by the Energy Supply Commercial Operations area.	MWH Hours Sold	Energy Markets - Regulated Trading (Gen Book) using MWH hours sold to allocate costs is reasonable because there is a direct causal relationship between trading activities and the MWH hours sold.	36.3840%
430	Energy Supply Asset Management	Energy Supply Asset Management services includes the labor and non-labor costs of providing management support to the Energy Supply organization, maximizing business value of the Energy Supply information systems, developing the business plan, optimizing plant inventory, and leading the development of asset management strategy and implementation	Asset/Revenue/Number of Employees	Energy Supply Asset Management services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	45.0776%
431	Energy Markets - Business Services	Energy Markets Business Services includes the labor and non-labor costs for financial analysis, budgeting and administrative support, managerial reporting and business planning and process initiatives, independent daily forward valuation and risk measurement of commodity transactions and system fuel and purchase power requirements to meet system loads, as well as proprietary or trading transactions; creates retail system load and energy forecasts providing regular updates to senior management and analyses of key drivers, reviews and provides comments to dealmakers on non-standard agreements and associated confirmation agreements in the areas of coal supply, gas supply, wood fuel, rail, trucking, structured power purchases and nuclear/uranium concentrates and services; provides analyses for electric/gas hedge studies and sensitivities; creates load management forecasts, jurisdictional peak demand forecasts, and cost of service studies for energy trading and marketing. This is primarily used by the Risk Management and Business Systems organizations.	Asset/Revenue/Number of Employees	Energy Markets - Business Services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	45.0776%
435	Customer Care 903	Customer Care (CC) 903 services includes the labor and non-labor costs for contact centers, remittance processing, credit and collections, customer resource management, and contact center training. This allocation is used when all four jurisdictions are benefiting from the services such as responding to residential customer inquiries regarding billings and outages, handling inbound credit calls, outbound collections calls, managing accounts receivables, training call center staffs, developing contact center call forecasts. This is primarily used by the Customer Care organization.	Number of Customers	Customer Care 903 using number of customers to allocate costs is reasonable because the costs are directly related to customers.	35.5399%
436	Customer Care 902	Customer Care 902 services includes the labor and non-labor costs for meter reading of retail and wholesale customers and determining consumption for billing purposes as well as executing field collections. This is primarily used by the Customer Care organization.	Number of Customers	Customer Care 902 using number of customers to allocate costs is reasonable because the costs are directly related to customers.	35.4976%
437	Customer Care 901	Customer Care 901 services includes the labor and non-labor costs for the leadership of the customer care organization and their administrative support staff such as consulting costs to support overall Customer Care organizational operations. This is primarily used by the Customer Care organization.	Number of Customers	Customer Care 901 using number of customers to costs is reasonable because the costs are directly related to customers.	35.5399%
439	Customer Care North 903	Customer Care 903 - North services includes the labor and non-labor costs for contact centers, and credit and collections, such as responding to commercial customers inquiries at the Business Solution Center in the North. This allocation is used when Northern States Power Company-Minnesota and Northern States Power Company-Wisconsin are the only jurisdictions benefiting from the services. This is primarily used by the Customer Care organization.	Number of Customers	Customer Care North 903 using number of customers to allocate costs is reasonable because the costs are directly related to customers.	84.0832%
440	Utilities Group Administrative & General FERC 921	Utilities Group A&G (Administrative and General) FERC 921 services includes the labor and non-labor costs for utilities group leadership, management and support services for the distribution, transmission, transportation and supply chain areas. This is primarily used by the Distribution and Transmission organizations.	Electric Transmission Plant/ Electric Distribution Plant/ Gas Transmission Plant/Gas Distribution Plant	Utilities Group Administrative & General FERC 921 using a ratio of Electric & Gas - Transmission & Distribution to allocate costs is reasonable because there is a direct causal relationship with operations supported by Utilities Group.	35.5340%
441	Distribution Electric FERC 580 (E&S)	Distribution Electric FERC 580 services includes the labor and non-labor costs for the engineering and supervision of the electric distribution organization. This is primarily used by the Safety and Transmission and Substations organizations.	Electric Distribution Plant	Distribution Electric FERC 580 (E&S) using the electric distribution plant to allocate the costs is reasonable because there is a direct causal relationship with the operations supported by Distribution Electric.	36.9665%
442	Transmission Electric FERC 560 (E&S)	Transmission Electric FERC 560 services includes the labor and non-labor costs for engineering and supervision of the electric transmission organization. This is primarily used by the Safety and Transmission and Substations organizations.	Electric Transmission Plant	Transmission Electric FERC 560 (E&S) using Electric Transmission Plant to allocate costs is reasonable because there is a direct causal relationship with the operations supported by Transmission Electric.	38.9163%
443	Distribution Gas FERC 870 (E&S)	Distribution Gas FERC 870 services includes the labor and non-labor costs for the engineering and supervision of the gas distribution organization. This is primarily used by the Safety and Transmission and Substations organizations.	Gas Distribution Plant	Using Gas Distribution to allocate Distribution Gas FERC 870 costs is reasonable because there is a direct causal relationship with the operations supported by Distribution Gas.	29.6370%
444	Transmission Gas FERC 850 (E&S)	Transmission Gas FERC 850 services includes the labor and non-labor costs for the engineering and supervision of the gas transmission organization. This is primarily used by the Safety organization.	Gas Transmission Plant	Distribution Gas FERC 870 (E&S) using gas transmission to allocate costs is reasonable because there is a direct causal relationship with the operations supported by transmission gas.	9.1853%
445	Distribution Gas FERC 880 (Misc)	Distribution Gas FERC 880 services includes the labor and non-labor costs for the engineering and supervision of the gas distribution organization not provided for in FERC 870. This includes activities such as operating street lighting systems and research and development costs.	Gas Distribution Plant	Distribution Gas FERC 880 (MISC) using Gas Distribution to allocate costs is reasonable because there is a direct causal relationship with the operations supported by Distribution Gas.	29.6370%

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446	Customer Care Low Income Assistance 908	Customer Care Low Income Assistance (908) services includes the labor and non-labor costs associated with the low income energy customer program such as answering calls from customers for referral to low income assistance agencies, providing information to the agencies in order to process applications for assistance, take pledges/commitments from agencies and process payments from agencies. This is primarily used by the Customer Care organization.	Number of Residential Customers/Number of Calls	Customer Care Low Income Assistance 908 using the composite of the average of the Special Needs Customer Contacts Ratio and Residential Customers Ratio to allocate costs is reasonable because the costs are directly related to both customers and number of low income calls.	39.0318%
447	Customer Billing FERC 903	Customer Billing FERC 903 includes the labor and non-labor costs related to the delivery of billing statements, letters and notices to Xcel customers including postage and outside services costs, oversight and administration of customer billing area, research of billing exceptions, providing escalated customer service assistance with regard to billing issues resolution, and process remittances and receivables. This allocation is used when all four jurisdictions are benefiting from the services	Number of Customer Bills	Customer Billing FERC 903 using number of customer bills to allocate costs is reasonable because the costs are directly related to customer billing activities.	39.8529%
449	Transm Elec 560 NSPM & NSPW	Transm Elec 560 NSPM & NSPW services includes the labor and non-labor costs for NSPM & NSPW engineering and supervision of the electric transmission organization. This allocation is used when Northern States Power Company-Minnesota and Northern States Power Company-Wisconsin are the only jurisdictions benefiting from the services. This is primarily used by the Safety and Transmission and Substations organizations.	Electric Transmission Plant	Transm Elec 560 NSPM & NSPW using electric transmission to allocate costs is reasonable because there is a direct causal relationship with the operations supported by Transmission Electric.	77.4636%
451	Transm Elec FERC 561.5	Transm Elec FERC 561.5 services include transmission reliability, planning and standards development labor and non-labor expenses for Xcel Energy Operating Companies related to transmission assets and reliability needs and transmission customers requirements and requests (i.e., developing and maintaining transmission system models, applying methodologies and tools for analysis and simulation of systems, notification of any planned transmission changes and impacts, etc.). This allocation is used when all four jurisdictions are benefiting from the services and processes.	Electric Transmission Plant	Transm Elec FERC 561.5 using electric transmission plant to allocate costs is reasonable because there is a direct causal relationship with the operations supported by Transmission Electric.	38.9163%
453	Distribution Elec FERC 586	Distribution Elec FERC 586 services include meter expenses labor and non-labor providing direction, operations, standards and processes relating to Xcel Energy operating companies i.e.: electric distribution meters standards and development, meter purchases, etc. This allocation is used when all four jurisdictions are benefiting from the services.	Electric Distribution Plant	Distribution Elec FERC 586 using distribution plant to allocate meter costs is reasonable because there is a direct causal relationship with the electric distribution plant and meter operations supported by electric distribution.	36.9665%
454	Distribution Gas FERC 878	Distribution Gas FERC 878 services include meter expenses labor and non-labor providing direction, operations, standards and processes relating to Xcel Energy Operating Companies i.e.: gas distribution meters standards and development, meter purchases, etc. This allocation is used when all four jurisdictions are benefiting from the services.	Gas Distribution Plant	Distribution Gas FERC 878 using gas distribution plant to allocate meter costs is reasonable because there is a direct causal relationship with the gas distribution plant and meter operations supported by gas distribution.	29.6370%
455	ES Misc Power Expense Op Co's	ES Misc Power Expense Op Co's services include Energy Supply operations performance services labor and non-labor costs for non-management employees with the following accountabilities: Develop / suggest / implement improvements for multiple power plants, standardize best practices and process improvements across multiple power plants, establish operations and maintenance policies and procedures for multiple power plants. This allocation is used when all four jurisdictions are benefiting from the services.	MWH Generation	ES Misc Power Expense Op Co's using MWH generation to allocate costs is reasonable because the costs are directly related to the support of the power plants.	32.1734%
456	ES Misc Power Expense North	ES Misc Power Expense North services include Energy Supply operations performance services labor and non-labor costs for non-management employees with the following accountabilities: Develop / suggest / implement improvements for multiple power plants, standardize best practices and process improvements across multiple power plants, establish operations and maintenance policies and procedures for multiple power plants. This allocation is used when NSPM & NSPW jurisdictions are benefiting from the services.	MWH Generation	ES Misc Power Expense North using MWH generation to allocate costs is reasonable because the costs are directly related to the support of the power plants.	93.7591%
458	ES Operations Management OPCo's	ES Operations Management OPCo's services include management of energy supply operations services labor and non-labor costs for the following accountabilities: Operate plant equipment within requirements, maintain plant equipment, manage plant personnel in accordance with labor contracts, suggest/implement plant improvements, maintain community relationships, establish operations and maintenance policies and procedures and overhaul planning and execution. This allocation is used when all four jurisdictions are benefiting from the services.	MWH Generation	ES Operations Management OPCo's using MWH generation to allocate costs is reasonable because the costs are directly related to the support of the power plants.	32.1734%
459	ES Operations Management North	ES Operations Management North services include management of energy supply operation services labor and non-labor costs for the following accountabilities: Operate plant equipment within requirements, maintain plant equipment, manage plant personnel in accordance with labor contracts, suggest/implement plant improvements, maintain community relationships, establish operations and maintenance policies and procedures and overhaul planning and execution. This allocation is used when NSPM & NSPW jurisdictions are benefiting from the services.	MWH Generation	ES Operations Management North using MWH generation to allocate costs is reasonable because the costs are directly related to the support of the power plants.	93.7591%
464	ES Environmental Policy & Services OPCo's	ES Environmental Policy & Services OPCo's functions which include the labor and non-labor costs dedicated to air quality, renewable energy, innovative technology and climate change, develop corporate compliance strategy, regulatory agency interaction (both at the federal and/or state level), permitting and compliance reporting, waste management, combustion byproducts management, environmental compliance auditing, provide support to the Environmental Council and assist with environmental communications strategies. This allocation is used when NSPM, NSPW, PSCo and SPS jurisdictions are benefiting from the services.	Electric Production Plant/ Electric Transmission Plant/ Electric Distribution Plant/ Gas Transmission Plant/ Gas Distribution Plant	ES Environmental Policy & Services OPCo's using gross plant assets to allocate costs is reasonable because the costs are directly related to the environmental policies and services which are generated by the operation and ownership of the assets.	41.1980%

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468	Transmission Elec FERC 566 - Finance Business Area	Transm Elec FERC 566 services include transmission electric labor and non-labor costs associated with accounting, budgeting, regulatory reporting, and capital asset accounting. This is primarily used by departments that fall underneath the Financial Performance and Planning such as Transmission Finance.	Asset/Revenue/Number of Employees	Transm Elec FERC 566 charges that can not be directly charged to a specific legal entity and are corporate in nature. The three factor formula is used because these charges are comprised of a broad spectrum of activities and no measurable method of cost causative allocation was found.	45.0776%
469	Elec Distribution FERC 588 - Finance Business Area	Elec Dist FERC 588 services include electric distribution labor and non-labor costs associated with accounting, budgeting, regulatory reporting, and capital asset accounting. This is primarily used by departments that fall underneath the Financial Performance and Planning such as Distribution Capital Finance.	Asset/Revenue/Number of Employees	Elec Dist FERC 588 charges that can not be directly charged to a specific legal entity and are corporate in nature. The three factor formula is used because these charges are comprised of a broad spectrum of activities and no measurable method of cost causative allocation was found.	45.0776%
470	Gas Distribution FERC 880 - Finance Business Area	Gas Dist FERC 880 services include gas distribution labor and non-labor costs associated with accounting, budgeting, regulatory reporting, and capital asset accounting. This is primarily used by departments that fall underneath the Financial Performance and Planning such as Gas Distribution Finance.	Asset/Revenue/Number of Employees	Gas Dist FERC 880 charges that can not be directly charged to a specific legal entity and are corporate in nature. The three factor formula is used because these charges are comprised of a broad spectrum of activities and no measurable method of cost causative allocation was found.	52.4080%
474	Gas Dist/Elec Dist/Gas Trans Finance FERC 588, 880, 859	Elec Dist, Gas Dist, & Gas Trans FERC 588, 880, 859 services include gas distribution, gas transmission, and electric distribution labor and non-labor costs associated with accounting, budgeting, and regulatory reporting. This is primarily used by departments that fall underneath the Financial Performance and Planning such as Distribution Finance.	Electric Distribution Plant/ Gas Transmission Plant/ Gas Distribution Plant	Elec Dist, Gas Dist, & Gas Trans FERC 588, 880, 859 charges that can not be directly charged to a specific business unit and are corporate in nature. Using a ratio of Electric Transmission & Gas Transmission/Distribution to allocate Utility Group costs is reasonable because there is a direct causal relationship with operations supported by Utilities Group.	33.5583%
500	Business Systems	Business Systems services includes the IT costs of providing assistance to computer users across the company. Specifically Computer technology risk, software maintenance on applications distributed to all users (i.e. Microsoft PC tools), governance and project management over all IT projects, fixed management fees with outside vendors, business analytics costs, amortization of outside vendor fees and costs that are not specific to an application that has a specific allocator. This is primarily used by the Business Systems organization.	Number of Computers	Business Systems using number of computers to allocate costs is reasonable because there is a direct causal relationship between the number of computers and the cost to support them.	58.5524%
503	CRS (Customer Resource System)	The CRS system includes the labor and non-labor costs for the CRS system, specifically, application development and maintenance costs, licensing fees, server system costs and technology risk costs specific to disaster recovery of this application. CRS is Xcel Energy's customer service and billing system. This is primarily used by the Business Systems organization.	Number of Meters/Number of Contacts	CRS (Customer Resource System) using a ratio of no. of meters/no. of contacts to allocate costs is reasonable because there is a direct causal relationship with the operations supported by CRS.	34.9813%
504	Maximo	Maximo is Energy Supply's enterprise asset management system. It is used to manage work and supply chain activities for 70+ power plants. In addition, it is the time entry system for all Energy Supply employees. The Maximo system includes the labor and non-labor costs for the Maximo system, including the application development and maintenance (ADM) costs, licensing fees, server system costs and technology risk costs specific to disaster recovery of this application. Maximo is the work management system for the Energy Supply business area. This is primarily used by the Business Systems organization.	Number of Maximo Users	Maximo using the no. of Maximo users to allocate the costs is reasonable because there is a direct causal relationship with the operations supported by Maximo.	32.4772%
505	JDE (J.D. Edwards)	JDE includes the labor and non-labor costs for JDE (J.D. Edwards) which serves as the general ledger system, including application development and maintenance costs, licensing fees, server system costs and technology risk costs specific to disaster recovery of this application. This is primarily used by the Business Systems organization.	Asset/Revenue/Number of Employees	JDE (J.D. Edwards) - The Business Systems expenses related to maintenance of this system that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	40.4599%
506	GIS (Geographic Information System)	GIS is a vendor-developed, server based automated asset mapping software package. The GIS Distribution system includes the labor and non-labor costs for the application development and maintenance of the distribution Geographic Information System. This is primarily used by the Business Systems organization.	Electric Distribution Plant/ Gas Distribution Plant	GIS (Geographic Information System) using a ratio of elec dist plant/gas dist plant to allocate costs is reasonable because GIS is used to map these distributions systems.	33.3018%
507	OMS (Outage Management System)	OMS is used for creating and routing gas/electric outage orders from CRS out to the mobile computers in Xcel Energy crew trucks. Costs include labor and non-labor for the application development and maintenance of the OMS. This is primarily used by the Business Systems organization.	Electric Distribution Plant/ Gas Distribution Plant	OMS (Outage Management System) using a ratio of elec dist plant/gas dist plant to allocate costs is reasonable because OMS is used to manage outages on these distribution systems.	33.3018%
508	e-Business	The e-Business system includes the labor and non-labor costs associated with the corporate electronic business infrastructure. This is primarily used by the Business Systems organization.	Number of Employees	E-Business using Number of Employees to allocate costs is reasonable because the costs benefit employees.	50.3402%
509	Passport - All Modules	Passport - All Modules includes the labor and non-labor costs for accounts payable, inventory, work management and purchasing. This includes application development and maintenance costs, licensing fees, server system costs and technology risk costs specific to disaster recovery of this application. This is primarily used by the Business Systems organization.	Total AP/ Inventory/ Work Management/ Purchase Transactions	Passport - All Modules using the total AP/inventory/WM/purch transactions to allocate the Passport costs is reasonable because there is a direct causal relationship with the companies who benefit from Passport.	35.8678%
510	Passport - Accounts Payable	Passport - Accounts Payable includes the labor and non-labor costs for only the Accounts Payable module within Passport. This is applicable for when work is only being done on this module. This includes application development and maintenance costs, licensing fees, server system costs and technology risk costs specific to disaster recovery of this application. This is primarily used by the Business Systems organization.	Accounts Payable Transactions	Passport - Accounts Payable using total AP transactions to allocate costs is reasonable because there is a direct causal relationship with the companies using the AP function of Passport.	35.5385%
512	Passport - Work Management	Passport - Work Management includes the labor and non-labor costs associated with the Work Management module within Passport. This includes application development and maintenance costs, licensing fees, server system costs and technology risk costs specific to disaster recovery of this application. This is primarily used by the Business Systems organization.	Work Management Transactions	Passport - Work Management using work management transactions to allocate costs is reasonable because there is a direct causal relationship with the companies using the work management function of Passport.	55.5091%

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513	Passport - Purchasing	Passport - Purchasing includes the labor and non-labor costs associated with the Purchasing module within Passport. This includes application development and maintenance costs, licensing fees, server system costs and technology risk costs specific to disaster recovery of this application. This is primarily used by the Business Systems organization.	Purchasing Transactions	Passport - Purchasing using purchasing transactions to allocate costs is reasonable because there is a direct causal relationship with the companies using the purchasing functions of Passport.	29.3543%
514	Miscellaneous Applications	Miscellaneous Applications includes the labor and non-labor costs associated with the management of information systems infrastructure and working with IT Project Managers to ensure that new systems are positioned to function as successfully as possible in terms of overall performance and communication with other systems. This is primarily used by the Business Systems organization.	Average of all Software Percentages	Miscellaneous Applications using average of all software systems to allocate costs is reasonable because Miscellaneous Applications is primarily the server costs supporting the software applications and benefits the companies using the software applications.	37.6487%
515	PeopleSoft	PeopleSoft includes the labor and non-labor operating costs for the human resource business system which is used for payroll and benefit information for employees. This includes the application development and maintenance costs, licensing fees, server system costs and technology risk costs specific to disaster recovery of this application. This is primarily used by the Business Systems organization.	Number of Employees	PeopleSoft using number of employees to allocate costs is reasonable because the costs are directly related to employees.	50.2642%
516	PowerPlant	PowerPlant includes the labor and non-labor operating costs for PowerPlant, which is the capital asset business system which includes the following modules: Fixed Assets, Power Tax, Property Tax, Projects, Budgets, Cost Repository, Depreciation studies and Depreciation forecast. This includes the application development and maintenance costs, licensing fees, server system costs and technology risk costs specific to disaster recovery of this application. This is primarily used by the Business Systems organization.	Total Plant	PowerPlant using total plant to allocate costs is reasonable because there is a direct causal relationship with the companies using PowerPlant to manage plant assets.	44.6276%
517	GMS (Gas Management System)	GMS supports Xcel Energy Gas Transportation business including contracts, nominations/allocations, end-user measurement, imbalance management, and input for billing, also supports gas system supply, other balancing services. Costs include labor and non-labor for the application development and maintenance of the Gas Management System. This is primarily used by the Business Systems organization.	Number of Gas Customers (incl Transp Cust)	GMS (Gas Management System) using number of gas customers to allocate costs is reasonable because this system benefits gas customers.	0.0017%
518	MDMS (Monitoring Device Management System)	MDMS is a device inventory and management system. The MDMS system includes the labor and non-labor operating costs for the application development and maintenance of the Monitoring Device Management System. This is primarily used by the Business Systems organization.	Number of Meters	MDMS (Monitoring Device Management System) using number of meters to allocate costs is reasonable because there is a direct causal relationship with the companies using MDMS to monitor meters.	35.9733%
519	CL/QM (Call Logging and Quality Management)	CL/QM includes the labor and non-labor operating costs for the application development and maintenance of the Call Logging and Quality Management system which is used to monitor and record calls for contact center training and leadership teams. This is primarily used by the Business Systems organization.	Number of Customers/ Number of Contacts	CL/QM (Call Logging and Quality Management) using a ratio of no. of customers/no. of contacts to allocate costs is reasonable because the system benefits current and potential customers using the Call Centers.	34.7646%
520	IVR (Interactive Voice Response)	IVR includes the labor and non-labor costs for the application development and maintenance of the Interactive Voice Response system which interacts with a customer calling Xcel Energy call centers. It is intended to help service customers without invoking a call center agent. If the call needs to be handled by an agent, account information and the reason for the call is determined which helps route the call to the appropriate agent. This is primarily used by the Business Systems organization.	Number of Contacts	IVR (Interactive Voice Response) using number of contacts to allocate costs is reasonable because this system is used to take and route customer calls and benefits customers using the Call Centers.	33.9893%
521	Time/Project Time Reporting System (PTRS)	Time/PTRS includes the labor and non-labor operating and maintenance costs of the corporate employee time reporting and labor distribution systems. PTRS captures input of labor details to a project/activity and interfaces employee labor to TIME for payroll and accounting. TIME is also used to load labor related overheads to labor transactions. This is primarily used by the Business Systems organization.	Number of Employees	Number of Employees using number of employees to allocate costs is reasonable because there is a direct causal relationship with the companies using TIME/PTRS to process payroll.	50.2642%
523	Network	Network services include the labor and non-labor costs for the operation, maintenance, and management of Xcel Energy's internal and external Information Technology Network. This includes circuits, firewalls and communication assets. This is primarily used by the Business Systems organization.	Phones/Radios/Computers	Network using a ratio of phones/radios/computers to allocate costs is reasonable because the network supports these major items.	53.1057%
524	DSS (Distributed Systems & Services) Support	DSS Support includes the labor and non-labor costs for corrective and preventative maintenance, security, data backup and recovery, and the help desk. This is primarily used by the Business Systems organization.	Number of Computers	DSS (Distributed Systems & Services) Support using number of computers to allocate costs is reasonable because there is a direct causal relationship between the number of computers and the cost to support them.	58.5524%
525	Utility Innovations	Utility Innovations services include the labor and non-labor costs incurred for initiatives to extend the lives of plant assets including servers, data storage and PC's. This is primarily used by the Business Systems organization.	Electric Transmission Plant/ Electric Distribution Plant/ Gas Transmission Plant/Gas Distribution Plant	Utility Innovations using delivery gross plant to allocate costs is reasonable because there is a direct causal relationship with the operations supported by Utility Innovations.	35.5340%
526	EMS-Transmission (Energy Mgmt System-SCADA)	EMS provides supervisory control and data acquisition of substation devices through Remote Terminal Units (RTUs). EMS -Transmission system includes the labor and non-labor costs for the application development and maintenance of the Electric Transmission Plant information operations. This is primarily used by the Business Systems organization.	Electric Transmission Plant	EMS-Transmission (Energy Mgmt System-SCADA) using electric transmission to allocate costs is reasonable because there is a direct causal relationship with the operations supported by EMS-Transmission.	38.9163%
527	EMS-Distribution (Energy Mgmt System-SCADA)	EMS provides supervisory control and data acquisition of substation devices through Remote Terminal Units (RTUs). EMS - Distribution system includes the labor and non-labor costs for application development and maintenance of the Electric Distribution Plant information operations. This is primarily used by the Business Systems organization.	Electric Distribution Plant	EMS-Distribution (Energy Mgmt System-SCADA) using electric distribution to allocate costs is reasonable because there is a direct causal relationship with the operations supported by EMS-Distribution.	36.9665%
528	EMS-Shared (Energy Mgmt System-SCADA)	EMS provides supervisory control and data acquisition of substation devices through Remote Terminal Units (RTUs). EMS-Shared system includes the labor and non-labor costs for the application development and maintenance of the Electric Transmission, Distribution and Production Plant information operations. This is primarily used by the Business Systems organization.	Electric Production Plant/ Electric Transmission Plant/ Electric Distribution Plant	EMS-Shared (Energy Mgmt System-SCADA) using a ratio of electric transmission/distribution/production to allocate costs is reasonable because there is a direct causal relationship with the operations supported by EMS-Shared.	41.7106%

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Work Order No.	Work Order Title	Description of Services Provided	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent 2016
531	Gas SCADA	The Gas SCADA (Supervisory Control and Data Acquisition) system includes the labor and non-labor costs for the application development and maintenance of the Gas SCADA system. SCADA is a windows-based systems that give the gas system operators the ability to monitor and control Xcel Energy's natural gas systems. Control rooms and systems are located at both Rice Street (MN) and Lookout Center (CO). This is primarily used by the Business Systems organization.	Gas Transmission Plant/ Gas Distribution Plant	Gas SCADA using a ratio of gas trans plant/gas dist plant to allocate costs is reasonable because the costs are directly related to the monitoring of gas distribution and transmission.	19.4112%
533	CBS/ALS/CFM	The CBS/ALS/CFM system includes the labor and non-labor operating and maintenance costs, from the Business Systems area, for the application development and maintenance of the Competisoft Budget System (CBS), Allocated Ledger System (ALS) and the Corporate Financial Modeling (CFM) tools used for budgeting input, corporate modeling, managerial reporting and forecasting. This is primarily used by the Business Systems organization.	Asset/Revenue/Number of Employees	CBS/ALS/CFM - The Business Systems expenses related to maintenance of this system that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	45.0776%
534	CES (Customer & Enterprise Solutions)	The CES includes the labor and non-labor costs for the leadership of the Customer & Enterprise Solutions organization and their administrative support staff. This is primarily used by the Business Systems organization.	Number of - Computers/Customers/Employees	Using a ratio of No. of Computers/Customers/Employees to allocated CES costs is reasonable because there is a direct causal relationship with the operations supported by CES.	48.1441%
540	Meter Reading Acquisition System (MRAS)	MRAS (Meter Reading Acquisition) collects meter readings from multiple sources, stores and manages meter readings in a repository and provides meter reading to customer and billing systems. It includes a repository of fixed network, Automated Meter Reading and handheld device meter readings. MRAS costs include the labor and non-labor operating costs used to collect meter readings from multiple sources. It stores and provides meter readings to customers and billing systems. This includes the application development and maintenance costs, and licensing fees of this application. This is primarily used by the Business Systems organization.	Number of Meters	Meter Reading Acquisition System (MRAS) using number of meters to allocate costs is reasonable because the costs are directly related to meters.	35.9733%
542	PCI (Power Cost Incorporated)	PCI (Power Cost Incorporated) includes the labor and non-labor operating costs which support Electronic Trading by providing hourly generation data by unit, bid information, and bid submission. This includes the application development and maintenance costs, and licensing fees of this application.	Asset/Revenue/Number of Employees	PCI (Power Cost Incorporated) - The Business Systems expenses related to maintenance of this system that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	45.0776%
544	EAI (Entrprs Applic Integrat)	EAI (Entrprs Applic Integrat) includes the labor and non-labor costs associated with the management of information systems infrastructure and working with IT Project Managers to ensure that new systems are positioned to function as successfully as possible in terms of overall performance and communication with other systems.	Average of a Select Set of Software Allocators	EAI (Entrprs Applic Integrat) using average of selected software systems to allocate costs is reasonable because EAI (Entrprs Applic Integrat) is primarily the server costs supporting the selected software applications and benefits the companies using the software applications.	38.5798%
549	CFO Systems	CFO Systems includes the labor and non-labor costs for the non-critical applications that support the Financial Operations business area. Such as Tax Data Consolidator, TWS, Treas & UPCS.	Asset/Revenue/Number of Employees	CFO Systems - The Business Systems expenses related to maintenance of this system that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	40.4599%
550	Human Resources (HR) Systems	HR Systems includes the labor and non-labor costs for the non-critical applications that support the Human Resources business area. Such as MyHR, IPAD, ATS (the job posting site).	Number of Employees	Using Number of Employees to allocate Human Resources (HR) systems costs is reasonable because the costs are directly related to employees.	50.3402%
551	Corporate Systems	Corporate Systems includes the labor and non-labor costs for the non-critical corporate systems such as Aperture and File Finder. This is primarily used by the Business Systems organization.	Asset/Revenue/Number of Employees	Corporate Systems - The Business Systems expenses related to maintenance of this system that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	40.4599%
552	Security Systems	Security Systems includes the labor and non-labor costs for the day to day O&M contractors in the Security Operations Center (SOC). The SOC provides services for the whole company related to enterprise security, including physical access, security monitoring and investigations. This is primarily used by the Business Systems organization.	Number of Employees	Security Systems using number of employees to allocate costs is reasonable because the costs are directly related to employees.	50.2642%
553	Energy Supply Systems	Energy Supply Systems includes the labor and non-labor costs for the non-critical applications that support the Energy Supply area. Such as Emissions Tracker, Labworks, Documentum and Meridian.	Number of Maximo Users	Energy Supply Systems using number of Maximo users to allocate costs is reasonable because Maximo is energy supply's enterprise asset management system and interfaces with a number of other critical systems.	32.4772%
554	Business Objects	Business Objects includes the labor and non-labor costs for the application that provides critical reporting from data universes.	Number of Business Object Users	Business Objects using number of Business Object users to allocate costs is reasonable because the costs are directly related to users who are able to access the application.	38.8669%
559	Mobile Computing	The Mobile Computing system includes the labor and non-labor costs for the maintenance and support for electric and gas distribution to our customers. This is primarily used by the Business Systems organization.	Electric Distribution Plant/ Gas Distribution Plant	Mobile Computing using a ratio of electric dist plant and gas dist plant to allocate costs is reasonable because Mobile Computing is used to support electric and gas distribution.	33.3018%
561	Enterprise Continuity	Enterprise Continuity includes the labor and non-labor costs for applications of all aspects of business continuity and reliability, contingency planning, readiness assessment, drills and planning for all hazards.	Asset/Revenue/Number of Employees	Enterprise Continuity - The Business Systems expenses related to maintenance of this system that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used.	40.4599%
562	Mainframe Charges From IBM	Labor and non-labor costs related to Mainframe IBM expenses for development, maintenance, and licensing. The Mainframe is comprised of 3 applications: Time, Gas Management System, and Monitoring Device Management System applications. This is used primarily by the Business Systems Organization.	Average of a Select Set of Software Allocators	Mainframe Charges From IBM expenses can not be directly charged to a specific legal entity as the system is used by multiple entities. Using an average of selected software systems to allocate costs is reasonable because Mainframe primarily supports these selected software systems.	28.7464%

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Work Order No.	Work Order Title	Description of Services Provided	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent 2016
563	SAP GL	SAP GL includes labor and non-labor costs related to SAP GL expenses for the implementation of the new General Ledger system	Asset/Revenue/Number of Employees	SAP GL - The SAP GL expenses related to the implementation of this system that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used.	40.4599%
10471	Integrated Talent Management	Create and send out an RFP to obtain an "implementer" of the Integrated Talent Management project. Identify bidders, evaluate responses, conduct interviews, and support the contracting process. The "implementer" will work with the Integrated Talent Management software suite to provide better and more closely aligned retention and recruitment tools.	Number of Employees	Integrated Talent Management - Number of Employees is a reasonable method of allocation because this software is used for recruitment and retention of employees.	50.3402%
10472	Wind Predictor Enhancement	Provide research and development of the enhancements to the Wind Predictor System. The Wind Predictor System assists Xcel Energy with forecasting power generation across Xcel's wind farm portfolio with the goal of reducing the Mean Absolute Error and passing on realized savings to ratepayers. The enhancements to the Wind Predictor system will assist Xcel Energy in providing data and strategic direction/communication for National Center for Atmospheric Research (NCAR/UCAR) NCAR. The enhancements fall into three categories: 1) Probabilistic Wind Energy Forecasts, 2) Extreme Weather Event Forecasts, and 3) Wind Ramp Forecasts.	MWH Hours Sold	Wind Predictor Enhancement - MWH Sold and MWH generation for wind are reasonable methods of allocation because the software is directly related to the electricity generated for sale coming from wind generation sources.	38.9116%
10493	Work and Asset Management Phase 1	This allocating work order will be used to track the design and requirements phase of the Productivity through Technology (PTT) project related to the replacement of our work and asset management system (WAMS) that will serve multiple operations functions. The Phase 1 portion of the design and requirement stage will identify systems that can provide a common approach, process and technology solution for work scheduling. A common approach will be defined across all of Operations including: Energy Supply, Transmission, Distribution, Gas and Supply Chain.	Number of Passport inventory, work management, purchasing transactions plus number of Maximo users	The number of Passport Inventory, work management, purchasing transactions plus number of Maximo users are a reasonable method of allocation because it's directly related to the scope of the project in the replacement of the work and asset management system (WAMS).	34.4026%
10507	Work and Asset Management Phase 2	This allocating work order will be used to track the design and requirements phase of the Productivity through Technology (PTT) project related to the replacement of our work and asset management system (WAMS) that will serve multiple operations functions. The Phase 2 portion of the design and requirement stage will continue to identify systems that can provide a common approach, process and technology solution for work scheduling. A common approach will be defined across all of Operations including: Energy Supply, Transmission, Distribution, Gas and Supply Chain.	Number of Passport inventory, work management, purchasing transactions plus number of Maximo users	The number of Passport Inventory, work management, purchasing transactions plus number of Maximo users are a reasonable method of allocation because it's directly related to the scope of the project in the replacement of the work and asset management system (WAMS).	34.4026%
10530	GL Design, Build Test Deploy	Implementation of the General Ledger Asset, activities include the design, build, test, deploy and post go-live support for the development of the application, technical architecture, training and performance support.	Asset/Revenue/Number of Employees	GL Design, Build Test Deploy - The GL Design, Build Test Deploy expenses related to the implementation of this system that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used.	40.4599%
10543	Field Sched & Dispatch	This allocating work order will be used to track the design and requirements phase of the Productivity through Technology (PTT) project related to the replacement of our work and asset management system (WAMS) that will serve multiple operations functions. The Phase 2 portion of the design and requirement stage will continue to identify systems that can provide a common approach, process and technology solution for work scheduling. A common approach will be defined across all of Operations including: Energy Supply, Transmission, Distribution, Gas and Supply Chain.	Number of Passport inventory, work management, purchasing transactions plus number of Maximo users	The number of Passport Inventory, work management, purchasing transactions plus number of Maximo users are a reasonable method of allocation because it's directly related to the scope of the project in the replacement of the work and asset management system (WAMS).	34.4026%
10544	ER Increased Strategic Sourcing	This allocating work order will be used to track the design and requirements phase of the Productivity through Technology (PTT) project related to the replacement of our work and asset management system (WAMS) that will serve multiple operations functions. The Phase 2 portion of the design and requirement stage will continue to identify systems that can provide a common approach, process and technology solution for work scheduling. A common approach will be defined across all of Operations including: Energy Supply, Transmission, Distribution, Gas and Supply Chain.	Number of Passport inventory, work management, purchasing transactions plus number of Maximo users	The number of Passport Inventory, work management, purchasing transactions plus number of Maximo users are a reasonable method of allocation because it's directly related to the scope of the project in the replacement of the work and asset management system (WAMS).	34.4026%
10545	ER Inventory Mgt & Material Flow Optimization	This allocating work order will be used to track the design and requirements phase of the Productivity through Technology (PTT) project related to the replacement of our work and asset management system (WAMS) that will serve multiple operations functions. The Phase 2 portion of the design and requirement stage will continue to identify systems that can provide a common approach, process and technology solution for work scheduling. A common approach will be defined across all of Operations including: Energy Supply, Transmission, Distribution, Gas and Supply Chain.	Number of Passport inventory, work management, purchasing transactions plus number of Maximo users	The number of Passport Inventory, work management, purchasing transactions plus number of Maximo users are a reasonable method of allocation because it's directly related to the scope of the project in the replacement of the work and asset management system (WAMS).	34.4026%
10546	ER Procurement Operations Optimization	This allocating work order will be used to track the design and requirements phase of the Productivity through Technology (PTT) project related to the replacement of our work and asset management system (WAMS) that will serve multiple operations functions. The Phase 2 portion of the design and requirement stage will continue to identify systems that can provide a common approach, process and technology solution for work scheduling. A common approach will be defined across all of Operations including: Energy Supply, Transmission, Distribution, Gas and Supply Chain.	Number of Passport inventory, work management, purchasing transactions plus number of Maximo users	The number of Passport Inventory, work management, purchasing transactions plus number of Maximo users are a reasonable method of allocation because it's directly related to the scope of the project in the replacement of the work and asset management system (WAMS).	34.4026%

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Work Order No.	Work Order Title	Description of Services Provided	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent 2016
10548	ER Talent Strategy	This allocating work order will be used to track the design and requirements phase of the Productivity through Technology (PTT) project related to the replacement of our work and asset management system (WAMS) that will serve multiple operations functions. The Phase 2 portion of the design and requirement stage will continue to identify systems that can provide a common approach, process and technology solution for work scheduling. A common approach will be defined across all of Operations including: Energy Supply, Transmission, Distribution, Gas and Supply Chain.	Number of Passport inventory, work management, purchasing transactions plus number of Maximo users	The number of Passport Inventory, work management, purchasing transactions plus number of Maximo users are a reasonable method of allocation because it's directly related to the scope of the project in the replacement of the work and asset management system (WAMS).	34.4026%
10549	ER Solution Strategy	This allocating work order will be used to track the design and requirements phase of the Productivity through Technology (PTT) project related to the replacement of our work and asset management system (WAMS) that will serve multiple operations functions. The Phase 2 portion of the design and requirement stage will continue to identify systems that can provide a common approach, process and technology solution for work scheduling. A common approach will be defined across all of Operations including: Energy Supply, Transmission, Distribution, Gas and Supply Chain.	Number of Passport inventory, work management, purchasing transactions plus number of Maximo users	The number of Passport Inventory, work management, purchasing transactions plus number of Maximo users are a reasonable method of allocation because it's directly related to the scope of the project in the replacement of the work and asset management system (WAMS).	34.4026%
10550	Enterprise Transformation Office	Supports the Implementation Phase for both the General Ledger and Early Release Assets Activities include Program Governance and Management, Change Management, Business Architecture, Cost Benefit Analysis and Benefits Realization, Enterprise Technical Architecture that is needed to implement the assets.	ETO Hours	The number of ETO Hours is a reasonable method of allocation for both the G/L and Early Release Assets as labor is the driving force in the implementation phase.	39.1209%
10555	WAM- Work and Asset Management Blueprint	Conducting Blueprint activities (Accenture Development Method Plan and Analyze project phases). Includes design of impacted business processes and implementation plan for delivery of the WAM solution.	Number of Passport inventory, work management, purchasing transactions plus number of Maximo users	The number of Passport Inventory, work management, purchasing transactions plus number of Maximo users is a reasonable method of allocation as there is a direct correlation to the implementation and delivery of the WAM solution.	34.4026%

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Work Order No.	Work Order Title	Description of Services Provided	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent 2016
110	Executive - Corporate Governance	Executive - Corporate Governance includes the labor and non-labor costs for executive corporate management, long-term business strategy development and other programs that ensure the continuity and development of management. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc. This is primarily used by the Chief Executive Officer, Chief Operating Officer, Chief Administrative Officer, the Corporate Secretary and the Aviation department.	Asset/Revenue/FTE Labor Hours	Executive - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Allocated FTE labor hours, including overtime, is used as ordered in Docket No. E, G-001/AI-10-690	39.8635%
114	Board of Directors - Corporate Governance	Board of Directors - Corporate Governance includes the labor and non-labor costs related to the Board of Directors (BOD). BOD costs may include Directors fees, retirement expenses and replacement fees; Board/Committee meetings and BOD related consulting. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc. This allocator is primarily used by the Corporate Secretary/Shareholder Relations department.	Asset/Revenue/FTE Labor Hours	Board of Directors - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Allocated FTE labor hours, including overtime, is used as ordered in Docket No. E, G-001/AI-10-690	39.8635%
115	Shareholder - Corporate Governance	Shareholder - Corporate Governance includes the labor and non-labor costs for serving as liaison between Xcel Energy BOD and the shareholders, manages employee/executive stock award matters, liaison between Xcel Energy and the proxy advisory group, monitoring stock ownership patterns, planning shareholder meetings, coordinating the transfer agent and shareholder record keeping functions. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc. This allocator is primarily used by the Corporate Secretary/Shareholder Relations department.	Asset/Revenue/FTE Labor Hours	Shareholder - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Allocated FTE labor hours, including overtime, is used as ordered in Docket No. E, G-001/AI-10-690	39.8635%
116	Investor Relations - Corporate Governance	Investor Relations - Corporate Governance includes the labor and non-labor costs for communications to investors and the financial community, providing management with feedback from investors, assisting in the communication to investors of debt and equity securities issuances, assists in the development of presentations for Board of Directors, develops and delivers Xcel Energy's credit story to credit rating agencies, develops and presents Xcel Energy investment story to investors, reviews all public financial documents for accuracy and completeness and distributes all financial releases. Corporate governance activities are general services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc. This allocator is primarily used by the Investor Relations area.	Asset/Revenue/FTE Labor Hours	Investor Relations - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Allocated FTE labor hours, including overtime, is used as ordered in Docket No. E, G-001/AI-10-690	39.8635%
120	Accounting, Reporting, & Taxes	Accounting, Reporting & Taxes services includes the labor and non-labor costs for preparation of operating and non-operating financial statements, tax returns and reporting, performing accounting for the employee benefit plans, ensuring compliance with applicable laws and regulations of the operating and non-operating companies; composing the corporate-wide regulatory accounting policy, and coordinating the budgeting process with the operating and non-operating companies. This is primarily used by departments that fall under the Controller such as Tax Services, Capital Asset Accounting, Regulatory Accounting, Commercial Accounting, and Corporate Budgeting.	Asset/Revenue/FTE Labor Hours	Accounting Reporting & Taxes services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.4496%

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Work Order No.	Work Order Title	Description of Services Provided	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent 2016
121	Accounting & Reporting - Corporate Governance	Accounting & Reporting - Corporate Governance includes the labor and non-labor costs associated with preparing and filing consolidated reporting and financial statements, preparing consolidated budgets, completing the consolidation process, maintaining the books and records of Xcel Energy Inc. and Service Company, composing the corporate-wide regulatory accounting policy and compliance, Sarbanes-Oxley (SOX) documentation and compliance, and Chief Financial Officer activities related to the Audit Committee. Provides financial leadership to Xcel Energy and provides policies, controls, and leadership to the Financial Operations business area. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc. This is primarily used by the CFO as well as departments that fall under the Controller such as Capital Asset Accounting, Regulatory Accounting, Commercial Accounting, and Corporate Budgeting.	Asset/Revenue/FTE Labor Hours	Accounting & Reporting - Corporate Governance - The three-factor formula reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Allocated FTE labor hours, including overtime, is used as ordered in Docket No. E, G-001/AI-10-690.	39.8635%
123	Accounting - Operating Companies	Accounting - Operating Companies includes the labor and non-labor costs associated with operating company revenue accounting, budgeting, regulatory reporting, sales and use taxes, business area support for utility areas, operating company budgeting support, and capital asset accounting. This is primarily used by departments that fall under the Controller such as Capital Asset Accounting, Regulatory Accounting, Commercial Accounting, and Corporate Budgeting.	Asset/Revenue/FTE Labor Hours	Accounting - Operating Companies services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.4659%
125	Acctg, Rptg, Tax - MN, WI	Acctg, Rptg, Tax - MN, WI includes the labor and non-labor costs associated with NSPM & NSPW revenue accounting, budgeting, regulatory reporting, sales and use taxes, business area support for utility areas, operating company budgeting support, and capital asset accounting. This is primarily used by departments that fall under the Controller such as Capital Asset Accounting, Regulatory Accounting, Commercial Accounting, and Corporate Budgeting.	Asset/Revenue/FTE Labor Hours	Acctg, Rptg, Tax - MN, WI services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to NSPM & NSPW who benefit from the services.	86.6013%
126	Acctg, Rptg, Tax - MN, WI Elec	Acctg, Rptg, Tax - MN, WI Elec Electric includes the labor and non-labor costs associated specifically with NSPM & NSPW Electric utility revenue accounting, budgeting, regulatory reporting, sales and use taxes, business area support for utility areas, operating company budgeting support, and capital asset accounting. This is primarily used by departments that fall under the Controller such as Capital Asset Accounting, Regulatory Accounting, Commercial Accounting, and Corporate Budgeting.	Asset/Revenue/FTE Labor Hours	Acctg, Rptg, Tax - MN, WI Elec services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to NSPM & NSPW electric utility who benefit from the services.	86.6013%
127	Acctg, Rptg, Tax - OpCos Elec	Acctg, Rptg, Tax - OpCos Elec includes the labor and non-labor costs associated specifically with operating company electric utility revenue accounting, budgeting, regulatory reporting, sales and use taxes, business area support for utility areas, operating company budgeting support, and capital asset accounting. This is primarily used by departments that fall under the Controller such as Capital Asset Accounting, Regulatory Accounting, Commercial Accounting, and Corporate Budgeting.	Asset/Revenue/FTE Labor Hours	Acctg, Rptg, Tax - OpCos Elec services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies electric utility who benefits from the services.	44.4659%
130	Audit Services	Audit Services includes the labor and non-labor costs for auditing operating and non-operating companies, evaluating and improving risk management, ethical conduct and the implementation of best practices for operating and non-operating companies, conducting financial operations and information system audits, performing audits and reviews for compliance with regulatory and legal requirements and contracts with vendors and other parties; establishing and reviewing internal controls for operating and non-operating companies, establishing and reviewing SOX compliance requirements/control testing and evaluating contract risks for the operating and non-operating companies. This is primarily used by the Audit Services department.	Asset/Revenue/FTE Labor Hours	Audit Services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.4496%
131	Audit Services - Corporate Governance	Audit Services Corporate Governance includes the labor and non-labor costs associated with the financial operations and information system audits of the holding company and service company; evaluating and improving risk management, corporate internal control guidelines and procedures; ethical conduct and the implementation of best practices, reviewing financial reporting requirements and controls under Sarbanes-Oxley legislative requirements, auditing of consolidated financial statements and activities related to the Audit Committee, performing audit and reviews for compliance with regulatory and legal requirements and contracts with vendors and other parties, providing consulting services to management for operational and process improvement reviews, assistance in internal investigations of fraud, administering the corporate compliance hotline, conflict of interest investigations, or other potential violations of the Xcel Energy Code of Conduct. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc. This is primarily used by the Audit Services department.	Asset/Revenue/FTE Labor Hours	Audit Services - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Allocated FTE labor hours, including overtime, is used as ordered in Docket No. E, G-001/AI-10-690	39.8635%
132	Audit Services - OpCos	Audit Services - OpCos includes the labor and non-labor costs for auditing operating companies, evaluating and improving risk management, ethical conduct and the implementation of best practices for operating companies, conducting financial operations and information system audits, performing audits and reviews for compliance with regulatory and legal requirements and contracts with vendors and other parties; establishing and reviewing internal controls for operating companies, establishing and reviewing SOX compliance requirements/control testing and evaluating contract risks for the operating companies. This is primarily used by the Audit Services department.	Asset/Revenue/FTE Labor Hours	Audit Services - OpCos services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	44.4659%

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Work Order No.	Work Order Title	Description of Services Provided	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent 2016
133	Audit Services - OpCos - Elect	Audit Services - OpCos - Elect includes the labor and non-labor costs for auditing operating companies electric utility, evaluating and improving risk management, ethical conduct and the implementation of best practices for operating companies electric utility, conducting financial operations and information system audits, performing audits and reviews for compliance with regulatory and legal requirements and contracts with vendors and other parties; establishing and reviewing internal controls for operating companies electric utility, establishing and reviewing SOX compliance requirements/control testing and evaluating contract risks for the operating companies electric utility. This is primarily used by the Audit Services department.	Asset/Revenue/FTE Labor Hours	Audit Services - OpCos - Elect services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies electric utility who benefit from the services.	44.4659%
134	Audit Services - OpCos - Gas	AUDIT OpCos Gas includes the labor and non-labor costs for auditing operating companies gas utility, evaluating and improving risk management, ethical conduct and the implementation of best practices for operating companies gas utility, conducting financial operations and information system audits, performing audits and reviews for compliance with regulatory and legal requirements and contracts with vendors and other parties; establishing and reviewing internal controls for operating companies gas utility, establishing and reviewing SOX compliance requirements/control testing and evaluating contract risks for the operating companies gas utility. This is primarily used by the Audit Services department.	Asset/Revenue/FTE Labor Hours	Audit Services - OpCos - Gas services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies gas utility who benefit from the services.	51.7808%
135	Capital Asset Acctg	Capital Asset Acctg includes the labor and non-labor costs associated with operating and non-operating company capital asset accounting, budgeting, regulatory reporting, business area support for utility areas, and operating company budgeting support. This is primarily used by Capital Asset Accounting.	Asset/Revenue/FTE Labor Hours	Capital Asset Acctg services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.3036%
140	Finance & Treasury	Finance & Treasury services includes the labor and non-labor costs related to equity and debt securities issuance, cash management, relationships with financial institutions, compliance with debt covenants, Service Company portion of General and Excess liability insurance, and management of the Pension Fund and 401k benefits for operating companies. This is primarily used by the Treasurer's organization.	Asset/Revenue/FTE Labor Hours	Finance & Treasury services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.4496%
141	Finance & Treasury - Corporate Governance	Finance & Treasury - Corporate Governance includes the labor and non-labor costs related to equity and debt securities issuance, relationships with financial institutions, cash management, investing activities and monitoring the capital markets, holding company commercial paper transactions, compliance with debt covenants, corporate-wide protection of assets from catastrophic loss using risk financing mechanisms including captive risk retention and design and negotiation of insurance contracts with commercial and industry mutual underwriters (Service Company portion of Auto Liability, Cyber, and various other insurance policies), supervising the asset management firms for the Pension Fund and 401k benefits. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc. This is primarily used by the Treasurer's organization.	Asset/Revenue/FTE Labor Hours	Finance & Treasury - Corporate Governance uses the three-factor formula because it reflects the complexity and risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Allocated FTE labor hours, including overtime, is used as ordered in Docket No. E, G-001/AI-10-690	39.8635%
142	Risk Management	Risk Management develops and negotiates security agreements with counterparties; reviews risk vendor creditworthiness for the Environmental Services group; supports wind generation, solar carbon offsets, emission allowances, bundled energy and RECs, biomass and other renewable energy purchase agreements; participates in industry contracts working groups; representing Xcel Energy operating utilities; performs production cost modeling and analysis for corporate budgeting; analyzing value and risks of structured purchases and generation system modifications; performs long range system modeling to evaluate large capacity acquisition alternatives; provides central coordination of annual capital funding process for Distribution and maintains and administers the Risk Registry database, evaluates and prioritizes specific risk mitigations for distribution assets; develops strategies for distribution infrastructure including building and implementing stochastic models for asset life-cycle analysis and other ad hoc asset specific requests; creates retail and system load and energy forecasts providing regular updates to senior management and analyses of key drivers; provides data support and analyses for financial disclosures; and provides analyses and reporting of current sales and peak demand levels relative to forecasts. This is primarily used by the Risk Management organization.	Asset/Revenue/FTE Labor Hours	Risk Management services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.4496%

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143	Risk Management - Corporate Governance	Risk Management Corporate Governance includes the labor and non-labor costs of providing administration of the Transaction Review Committee which handles contract and deal approvals for Commercial Operations, Resource Planning and Energy Supply, provides analysis associated with key risks facing Xcel Energy Inc., negotiates and manages required security (e.g., bank letters of credit, bonds and guarantees among others); reviews and approves all documents requiring Contracts area sign-off. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc. This is primarily used by the Risk Management area.	Asset/Revenue/FTE Labor Hours	Risk Management - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Allocated FTE labor hours, including overtime, is used as ordered in Docket No. E-G-001/AI-10-690	39.8635%
146	Risk Mgmt - OpCos	Risk Mgmt - OpCos includes the labor and non-labor costs of oversight and administrative of operating company risk management work, working with counterparties to establish enabling agreements with operating companies, risk management reports including all operating companies (such as CDAD - Contract Development, Approval & Delegation or TRC- Transaction Review Committee Reporting).	Asset/Revenue/FTE Labor Hours	Risk Mgmt - OpCos services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	44.4659%
147	Captive Insurance	Captive Insurance - The Property Loss Control Engineers services includes the labor and non-labor costs for each primary Operating Company(s) (OpCos) as well as all of Energy Supply Services. Having an expertise in an area, they lend support to each other and members of Energy Supply, and the Utilities Group, throughout the corporation. Fire Protection, Transformer Maintenance, Turbine Characteristics, Policies and Procedures are some of the areas in which expertise has been developed. This expertise is then shared on a regular basis to the benefit of all OpCos and it is further shared at periodic Engineering meetings hosted by Hazard Insurance, which bring together Engineers from the OpCos, the Property Loss Control Engineers and Insurance Company representatives to promote Loss Control.	Asset/Revenue/FTE Labor Hours	Captive Insurance - OpCos services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	44.4659%
161	Corporate Strategy & Bus Dev - Corporate Governance	Corporate Strategy & Business Development - Corporate Governance includes the labor and non-labor costs associated with providing leadership for the implementation of company-wide business strategies and plans; portfolio management including the evaluation of potential opportunities for mergers, acquisitions and divestitures; providing financial, analytical and reporting support; researching and providing business intelligence information. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc. This allocator is primarily used by the Portfolio Strategy area.	Asset/Revenue/FTE Labor Hours	Corporate Strategy & Bus Dev - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Allocated FTE labor hours, including overtime, is used as ordered in Docket No. E-G-001/AI-10-690	39.8635%
162	Corp Strategy & Bus Dev - OpCo	Corp Strategy & Bus Dev - OpCo services includes the labor and non-labor costs associated with studying developing and demonstrating new energy technologies for future utility uses; providing operating company strategy and planning support, and providing leadership for Xcel Energy's renewable energy strategy and business development. This allocator is primarily used by the Portfolio Strategy business area.	Asset/Revenue/FTE Labor Hours	Corp Strategy & Bus Dev - OpCo services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	44.4659%
163	LEGAL OPCo Electric	LEGAL OPCo Electric services includes the labor and non-labor costs for operating companies electric utility legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts. This is primarily used by the General Counsel area.	Asset/Revenue/FTE Labor Hours	LEGAL OPCo Electric services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies electric utility who benefit from the services.	44.4659%
164	Legal OPCo Gas	Legal OPCo Gas NSPM, NSPW and PSCO Gas services includes the labor and non-labor costs for operating companies gas utility legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts. This is primarily used by the General Counsel area.	Asset/Revenue/FTE Labor Hours	Legal - OpCos Gas services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	51.7808%
170	Legal	Legal services includes the labor and non-labor costs for operating and non-operating legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts. This is primarily used by the General Counsel area.	Asset/Revenue/FTE Labor Hours	Legal services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.4496%

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171	Legal - Corporate Governance	Legal services Corporate Governance includes the labor and non-labor costs for anticipating and fulfilling the legal needs of Xcel Energy, its Board of Directors, officers, legal entities, business areas and corporate operations to protect the company's assets and to minimize potential liability. Provides services related to labor and employment law pertaining to Service Company employees, litigation, contracts, rates and regulation, environmental matters and other legal matters. Supports Xcel Energy and its subsidiaries in fulfilling corporate and business area strategies ranging from maintaining/improving regulatory relationships to continued leadership on environmental issues. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc. This allocator is primarily used by the General Counsel area.	Asset/Revenue/FTE Labor Hours	Legal - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Allocated FTE labor hours, including overtime, is used as ordered in Docket No. E, G-001/AI-10-690	39.8635%
172	Legal - NSPM & NSPW	Legal - NSPM & NSPW services includes the labor and non-labor costs for NSPM & NSPW operating companies legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts. This is primarily used by the General Counsel area.	Asset/Revenue/FTE Labor Hours	Legal - NSPM & NSPW services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to NSPM & NSPW who benefit from the services.	86.6013%
173	Legal - NSPM & NSPW Electric	Legal - NSPM & NSPW Electric services includes the labor and non-labor costs for NSPM & NSPW operating companies electric legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts. This is primarily used by the General Counsel area.	Asset/Revenue/FTE Labor Hours	Legal - NSPM & NSPW services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to NSPM & NSPW electric utility who benefit from the services.	86.6013%
174	Legal - OpCos	Legal - OpCos services includes the labor and non-labor costs for operating companies legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts. This is primarily used by the General Counsel area.	Asset/Revenue/FTE Labor Hours	Legal - OpCos services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	44.4659%
180	Communications - Corporate Governance	Communications - Corporate Governance includes the labor and non-labor costs to assist and ensure Executive Management, Investor Relations and others communicate appropriately with shareholders, the public, and other key stakeholder audiences. Key projects include: development and production of the annual report and other communications to investors; speeches, videos, and major presentations delivered by top executives; and speeches, displays, video and presentations for the company's annual meeting of shareholders. Media Relations contributes to building Xcel Energy's reputation by developing media and public relations strategies for major company initiatives and issues; responding to news media inquiries; working pro-actively with the media to forward story ideas and information about company events, policies and actions, and providing media training for company spokespersons. Media Relations also plays a key role in crisis communications and emergency preparedness efforts. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc. This allocator is primarily used by the Corporate Communications area.	Asset/Revenue/FTE Labor Hours	Communications - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Allocated FTE labor hours, including overtime, is used as ordered in Docket No. E, G-001/AI-10-690	39.8635%
181	Employee Communications	Employee Communications includes the labor and non-labor costs for the development and enhancement of employee awareness and understanding of the company's strategies, priorities, decisions and performance objectives. It develops and produces regular communication vehicles, including TODAY (daily news bulletin on intranet); XTRA (monthly print publication for all employees and retirees); All Managers E-mail (real-time communication for employees who supervise and manage others); Focus on Financials for all employees; targeted communications for specific business areas, such as Human Resources, and employee meetings. This is primarily used by the Corporate Communications area.	FTE Labor Hours	Employee Communications using allocated FTE labor hours, including overtime, is used as ordered in Docket No. E, G-001/AI-10-690 because the costs are directly related to employees.	48.4923%
182	Xcel Foundation	Xcel Foundation services includes the labor and non-labor costs associated with the management and administration of the Xcel Energy Foundation. This is primarily used by the Corporate Communications area which manages the Xcel Energy Foundation.	Asset/Revenue/FTE Labor Hours	Xcel Foundation services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	40.5949%
184	Branding	Branding services includes the labor and non-labor costs for brand advertising and management of community affairs programs such as employee volunteerism, educational programs and community events, the company's investment in major sponsorships such as the Xcel Energy Center as well as ensuring that such sponsorships and related activities support the company's brand, mission and values. This allocator is primarily used by the Corporate Communications area.	Asset/Revenue/FTE Labor Hours	Branding services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	40.5949%

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189	Human Resources (HR) - Corporate Governance	HR services Corporate Governance includes the labor and non-labor costs for executive officers' and Service Company employees' compensation plans, corporate HR policies, executive policy benefit plans, payroll services for Service Company and the employees' handbook. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc. This is primarily used by the Human Resources and Safety organizations.	Asset/Revenue/FTE Labor Hours	Human Resources (HR) - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative affect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative affect on the consolidated business. Allocated FTE labor hours, including overtime, is used as ordered in Docket No. E, G-001/AI-10-690	39.8635%
190	Human Resources (Diversity/Safety/Emp Relations)	HR-Diversity/Safety/Employee Relations includes the labor and non-labor costs for work performed for operating and affiliate company employees, such as diversity programs, providing workforce relations resources for labor agreements, arbitration, and training. Manage, design, and implement Corporate Safety initiatives. This is primarily used by the Human Resources and Safety organizations.	FTE Labor Hours	Human Resources (Diversity/Safety/Emp Relations) using allocated FTE labor hours, including overtime, is use as ordered in Docket No. E, G-001/AI-10-690 because the costs are directly related to employees.	48.5050%
197	Human Resources - Operating Companies	HR-Operating Companies services includes the labor and non-labor costs for work performed for operating and affiliate company employees such as diversity programs, providing workforce relations resources and labor agreements, design and implement Corporate Safety initiatives, provide online training and open enrollment classes, provide individual and team development coaching and employee engagement, provide strategic and tactical consulting on HR strategies and planning. This is primarily used by the Human Resources and Safety organizations.	FTE Labor Hours	Human Resources - Operating Companies using allocated FTE labor hours, including overtime, is use as ordered in Docket No. E, G-001/AI-10-690 because the costs are directly related to employees.	48.5050%
198	Payroll	Payroll services include the labor and non-labor costs for processing payroll including consolidation of time collection, calculation of salaries and wages, administration of employee deductions, account distribution and reconciliation, allocation and accounting for employment taxes and compliance reports. This is primarily used by the Human Resources area.	FTE Labor Hours	Payroll using allocated FTE labor hours, including overtime, is use as ordered in Docket No. E, G-001/AI-10-690 because the costs are directly related to employees.	48.4923%
199	Human Resources - Recruitment	HR-Recruitment services includes the labor and non-labor costs for work performed for operating and affiliate company employees such as employee recruitment, staffing administration for non-bargaining positions and provides Affirmative Action plans (development) and government audit management (compliance). This is primarily used by the Human Resources area.	FTE Labor Hours	Human Resources - Recruitment using allocated FTE labor hours, including overtime, is use as ordered in Docket No. E, G-001/AI-10-690 because the costs are directly related to employees.	48.5050%
409	Federal Lobbying	Federal Lobbying services includes the labor and non-labor costs for federal and state lobbying activities and the federal Political Action Committee (PAC). This is primarily used by the Federal and State Affairs organization.	Asset/Revenue/FTE Labor Hours	Federal Lobbying services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are provided to a subset of companies based on who benefits from the services. These costs are recorded in FERC 426.4.	39.9676%
410	Governmental Affairs	Governmental Affairs includes the labor and non-labor costs associated with the interpretation of laws regulations and environmental policy to ensure compliance and cost effectiveness for Xcel Energy customers and stockholders internal legislative policy development and issues management, appraise management and internal customers of political and policy trends and developments, develop and maintain relationships with regulatory officials and staff. This is primarily used by Federal and State Affairs and the Environmental areas.	Asset/Revenue/FTE Labor Hours	Governmental Affairs services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	39.9676%
416	Supply Chain	Supply Chain includes the labor and non-labor costs for operating companies diversity program expenses as well as various dues for specific sponsored agencies (Chamber of Commerce, social service dues, etc.)	Asset/Revenue/FTE Labor Hours	Supply chain services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	44.4659%
430	Energy Supply Asset Management	Energy Supply Asset Management services includes the labor and non-labor costs of providing management support to the Energy Supply organization, maximizing business value of the Energy Supply information systems, developing the business plan, optimizing plant inventory, and leading the development of asset management strategy and implementation.	Asset/Revenue/FTE Labor Hours	Energy Supply Asset Management services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.4659%
431	Energy Markets - Business Services	Energy Markets Business Services includes the labor and non-labor costs for financial analysis, budgeting and administrative support, managerial reporting and business planning and process initiatives, independent daily forward valuation and risk measurement of commodity transactions and system fuel and purchase power requirements to meet system loads, as well as proprietary or trading transactions; creates retail system load and energy forecasts providing regular updates to senior management and analyses of key drivers, reviews and provides comments to dealmakers on non-standard agreements and associated confirmation agreements in the areas of coal supply, gas supply, wood fuel, rail, trucking, structured power purchases and nuclear/uranium concentrates and services; provides analyses for electric/gas hedge studies and sensitivities; creates load management forecast, jurisdictional peak demand forecasts, and cost of service studies for energy trading and marketing. This is primarily used by the Risk Management and Business Systems organizations.	Asset/Revenue/FTE Labor Hours	Energy Markets - Business Services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.4659%

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468	Transmission Elec FERC 566 - Finance Business Area	Transm Elec FERC 566 services include transmission electric labor and non-labor costs associated with accounting, budgeting, regulatory reporting, and capital asset accounting. This is primarily used by departments that fall underneath the Financial Performance and Planning such as Transmission Finance.	Asset/Revenue/FTE Labor Hours	Transm Elec FERC 566 charges that can not be directly charged to a specific legal entity and are corporate in nature. The three factor formula is used because these charges are comprised of a broad spectrum of activities and no measurable method of cost	44.4659%
469	Elec Distribution FERC 588 - Finance Business Area	Elec Dist FERC 588 services include electric distribution labor and non-labor costs associated with accounting, budgeting, regulatory reporting, and capital asset accounting. This is primarily used by departments that fall underneath Financial Performance and Planning such as Distribution Capital Finance	Asset/Revenue/FTE Labor Hours	Elec Dist FERC 588 charges that can not be directly charged to a specific legal entity and are corporate in nature. The three factor formula is used because these charges are comprised of a broad spectrum of activities and no measurable method of cost ca	44.4659%
470	Gas Distribution FERC 880 - Finance Business Area	Gas Dist FERC 880 services include gas distribution labor and non-labor costs associated with accounting, budgeting, regulatory reporting, and capital asset accounting. This is primarily used by departments that fall underneath the Financial Performance and Planning such as Gas Distribution Finance.	Asset/Revenue/FTE Labor Hours	Gas Dist FERC 880 charges that can not be directly charged to a specific legal entity and are corporate in nature. The three factor formula is used because these charges are comprised of a broad spectrum of activities and no measurable method of cost cau	51.7808%
505	JDE (J.D. Edwards)	JDE includes the labor and non-labor costs for JDE (J.D. Edwards) which serves as the general ledger system, including application development and maintenance costs, licensing fees, server system costs and technology risk costs specific to disaster recovery of this application. This is primarily used by the Business Systems organization.	Asset/Revenue/FTE Labor Hours	JDE (J.D. Edwards) - The Business Systems expenses related to maintenance of this system that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	39.8635%
508	e-Business	The e-Business system includes the labor and non-labor costs associated with the corporate electronic business infrastructure. This is primarily used by the Business Systems organization.	FTE Labor Hours	E-Business using allocated FTE labor hours, including overtime, is use as ordered in Docket No. E, G-001/AI-10-690 because the costs benefit employees.	48.5050%
514	Miscellaneous Applications	Miscellaneous Applications includes the labor and non-labor costs associated with the management of information systems infrastructure and working with IT Project Managers to ensure that new systems are positioned to function as successfully as possible in terms of overall performance and communication with other systems. This is primarily used by the Business Systems organization.	Average of all Software Percentages	Miscellaneous Applications using average of all software systems to allocate costs is reasonable because Miscellaneous Applications is primarily the server costs supporting the software applications and benefits the companies using the software applications.	37.3782%
515	PeopleSoft	PeopleSoft includes the labor and non-labor operating costs for the human resource business system which is used for payroll and benefit information for employees. This includes the application development and maintenance costs, licensing fees, server system costs and technology risk costs specific to disaster recovery of this application. This is primarily used by the Business Systems organization.	FTE Labor Hours	PeopleSoft using allocated FTE labor hours, including overtime, is use as ordered in Docket No. E, G-001/AI-10-690 because the costs are directly related to employees.	48.4923%
521	Time/Project Time Reporting System (PTRS)	Time/PTRS includes the labor and non-labor operating and maintenance costs of the corporate employee time reporting and labor distribution systems. PTRS captures input of labor details to project/activity and interfaces employee labor to TIME for payroll and accounting. TIME is also used to load labor related overheads to labor transactions. This is primarily used by the Business Systems organization.	FTE Labor Hours	Number of Employees using allocated FTE labor hours, including overtime, is use as ordered in Docket No. E, G-001/AI-10-690 because there is a direct causal relationship with the companies using TIME/PTRS to process payroll.	48.4923%
533	CBS/ALS/CFM	The CBS/ALS/CFM system includes the labor and non-labor operating and maintenance costs from the Business Systems area, for the application development and maintenance of the Competisoft Budget System (CBS), Allocated Ledger System (ALS) and the Corporate Financial Modeling (CFM) tools used for budgeting input, corporate modeling, managerial reporting and forecasting. This is primarily used by the Business Systems organization.	Asset/Revenue/FTE Labor Hours	CBS/ALS/CFM - The Business Systems expenses related to maintenance of this system that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.4659%
534	CES (Customer & Enterprise Solutions)	The CES includes the labor and non-labor costs for the leadership of the Customer & Enterprise Solutions organization and their administrative support staff. This is primarily used by the Business Systems organization.	Number of - Computers/Customers, FTE Labor Hours	Using a ratio of No. of Computers/Customers, FTE Labor Hours to allocate CES costs is reasonable because there is a direct causal relationship with the operations supported by CES.	47.5324%
542	PCI (Power Cost Incorporated)	PCI (Power Cost Incorporated) includes the labor and non-labor operating costs which support Electronic Trading by providing hourly generation data by unit, bid information, and bid submission. This includes the application development and maintenance costs, and licensing fees of this application.	Asset/Revenue/FTE Labor Hours	PCI (Power Cost Incorporated) - The Business Systems expenses related to maintenance of this system that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.4659%
544	EAI (Entrprs Applic Integrat)	EAI (Entrprs Applic Integrat) includes the labor and non-labor costs associated with the management of information systems infrastructure and working with IT Project Managers to ensure that new systems are positioned to function as successfully as possible in terms of overall performance and communication with other systems.	Average of a Select Set of Software Allocators	EAI (Entrprs Applic Integrat) using average of selected software systems to allocate costs is reasonable because EAI (Entrprs Applic Integrat) is primarily the server costs supporting the selected software applications and benefits the companies using the software applications.	38.1808%
549	CFO Systems	CFO Systems includes the labor and non-labor costs for the non-critical applications that support the Financial Operations business area. Such as Tax Data Consolidator, TWS, Trecc & UPCS	Asset/Revenue/FTE Labor Hours	CFO Systems - The Business Systems expenses related to maintenance of this system that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	39.8635%
550	Human Resources (HR) Systems	HR Systems includes the labor and non-labor costs for the non-critical applications that support the Human Resources business area. Such as MyHR, IPAD, ATS (the job posting site).	FTE Labor Hours	Using allocated FTE labor hours, including overtime, is use as ordered in Docket No. E, G-001/AI-10-690 because the costs are directly related to employees.	48.5050%
551	Corporate Systems	Corporate Systems includes the labor and non-labor costs for the non-critical corporate systems such as Aperture and File Finder. This is primarily used by the Business Systems organization.	Asset/Revenue/FTE Labor Hours	Corporate Systems - The Business Systems expenses related to maintenance of this system that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	39.8635%

NSPM

Service Company Allocation Descriptions, Methods and NSPM Percentages *(using allocated FTE hours as ordered in Docket No. E, G-001/AI-10-690)*
2016 Test Year Budget

Work Order No.	Work Order Title	Description of Services Provided	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent 2016
552	Security Systems	Security Systems includes the labor and non-labor costs for the day to day O&M contractors in the Security Operations Center (SOC). The SOC provides services for the whole company related to enterprise security, including physical access, security monitoring and investigations. This is primarily used by the Business Systems organization.	FTE Labor Hours	Security Systems using allocated FTE labor hours, including overtime, is use as ordered in Docket No. E, G-001/AI-10-690 because the costs are directly related to employees.	48.4923%
561	Enterprise Continuity	Enterprise Continuity includes the labor and non-labor costs for applications of all aspects of business continuity and reliability, contingency planning, readiness assessment, drills and plans for all hazards.	Asset/Revenue/FTE Labor Hours	Enterprise Continuity - The Business Systems expenses related to maintenance of this system that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used.	39.8635%
562	Mainframe Charges From IBM	Labor and non-labor costs related to Mainframe IBM expenses for development, maintenance and licensing. The Mainframe is comprised of 3 applications: Time, Gas Management System and Monitoring Device Management System applications. This is used primarily by the Business Systems Organization.	Average of a Select Set of Software Allocators	Mainframe Charges From IBM expenses can not be directly charged to a specific legal entity as the system is used by multiple entities. Using an average of selected software systems to allocate costs is reasonable because Mainframe primarily supports these selected software systems.	28.1558%
563	SAP GL	SAP GL includes labor and non-labor costs related to SAP GL expenses for the implementation of the new General Ledger system	Asset/Revenue/FTE Labor Hours	SAP GL - The SAP GL expenses related to the implementation of this system that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used.	39.8635%
10471	Integrated Talent Management	Create and send out an RFP to obtain an "implementer" of the Integrated Talent Management project. Identify bidders, evaluate responses, conduct interviews, and support the contracting process. The "implementor" will work with the Integrated Talent Management software suite to provide better and more closely aligned retention and recruitment tools.	FTE Labor Hours	Using allocated FTE labor hours, including overtime, is use as ordered in Docket No. E, G-001/AI-10-690 because the costs are directly related to employees.	48.5050%
10530	GL Design, Build Test Deploy	Implementation of the General Ledger Asset, activities include the design, build, test, deploy and post go-live support for the development of the application, technical architecture, training and performance support.	Asset/Revenue/FTE Labor Hours	GL Design, Build Test Deploy - The GL Design, Build Test Deploy expenses related to the implementation of this system that could not be directly charged to a specific legal entity are corporate in nature. Because the services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used.	39.8635%

Workorder Number	Workorder Title	Allocation Method	2016 NSPM Alloc Percent	Allocation Statistics							
110	Executive - Corporate Governance	Asset/Revenue/Number of Employees	40.4599%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPM No. of Empl - 4,661	Total No. of Empl - 9,273		
114	Board of Directors - Corporate Governance	Asset/Revenue/Number of Employees	40.4599%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPM No. of Empl - 4,661	Total No. of Empl - 9,273		
115	Shareholder - Corporate Governance	Asset/Revenue/Number of Employees	40.4599%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPM No. of Empl - 4,661	Total No. of Empl - 9,273		
116	Investor Relations - Corporate Governance	Asset/Revenue/Number of Employees	40.4599%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPM No. of Empl - 4,661	Total No. of Empl - 9,273		
120	Accounting, Reporting, & Taxes	Asset/Revenue/Number of Employees	45.0621%	NSPM Assets - \$16,722,524	Total Assets - \$38,244,299	NSPM Revenues - \$5,022,827	Total Revenues - \$12,214,868	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259		
121	Accounting & Reporting - Corporate Governance	Asset/Revenue/Number of Employees	40.4599%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPM No. of Empl - 4,661	Total No. of Empl - 9,273		
123	Accounting - Operating Companies	Asset/Revenue/Number of Employees	45.0776%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259		
125	Acctg, Rptg, Tax - MN, WI	Asset/Revenue/Number of Employees	87.3597%	NSPM Assets - \$16,722,524	Total Assets - \$18,999,262	NSPM Revenues - \$5,022,827	Total Revenues - \$5,882,711	NSPM No. of Empl - 4,661	Total No. of Empl - 5,256		
126	Acctg, Rptg, Tax - MN, WI Elec	Asset/Revenue/Number of Employees	87.3597%	NSPM Assets - \$16,722,524	Total Assets - \$18,999,262	NSPM Revenues - \$5,022,827	Total Revenues - \$5,882,711	NSPM No. of Empl - 4,661	Total No. of Empl - 5,256		
127	Acctg, Rptg, Tax - OpCos Elec	Asset/Revenue/Number of Employees	45.0776%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259		
128	Prop Trading - Back Office	Joint Operating Agreement Peak Hour Megawatt Load Ratio	42.1976%	NSPM Average Percent 42.20%	Total Percent - 100.00%						
129	Gen/Prop Trading - Back Office	Joint Operating Agreement Labor Hours Ratio	26.2401%	NSPM Average Percent 26.24%	Total Percent - 100.00%						
130	Audit Services	Asset/Revenue/Number of Employees	45.0621%	NSPM Assets - \$16,722,524	Total Assets - \$38,244,299	NSPM Revenues - \$5,022,827	Total Revenues - \$12,214,868	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259		
131	Audit Services - Corporate Governance	Asset/Revenue/Number of Employees	40.4599%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPM No. of Empl - 4,661	Total No. of Empl - 9,273		
132	Audit Services - OpCos	Asset/Revenue/Number of Employees	45.0776%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259		
133	Audit Services - OpCos - Elect	Asset/Revenue/Number of Employees	45.0776%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259		
134	Audit Services - OpCos - Gas	Asset/Revenue/Number of Employees	52.4080%	NSPM Assets - \$16,722,524	Total Assets - \$33,542,481	NSPM Revenues - \$5,022,827	Total Revenues - \$10,281,981	NSPM No. of Empl - 4,661	Total No. of Empl - 7,965		
135	Capital Asset Acctg	Asset/Revenue/Number of Employees	44.9211%	NSPM Assets - \$16,722,524	Total Assets - \$38,583,119	NSPM Revenues - \$5,022,827	Total Revenues - \$12,226,509	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259		
140	Finance & Treasury	Asset/Revenue/Number of Employees	45.0621%	NSPM Assets - \$16,722,524	Total Assets - \$38,244,299	NSPM Revenues - \$5,022,827	Total Revenues - \$12,214,868	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259		
141	Finance & Treasury - Corporate Governance	Asset/Revenue/Number of Employees	40.4599%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPM No. of Empl - 4,661	Total No. of Empl - 9,273		
142	Risk Management	Asset/Revenue/Number of Employees	45.0621%	NSPM Assets - \$16,722,524	Total Assets - \$38,244,299	NSPM Revenues - \$5,022,827	Total Revenues - \$12,214,868	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259		
143	Risk Management - Corporate Governance	Asset/Revenue/Number of Employees	40.4599%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPM No. of Empl - 4,661	Total No. of Empl - 9,273		
144	Prop Trading - Ftr/Mid Office	Joint Operating Agreement Peak Hour Megawatt Load Ratio	42.1976%	NSPM Average Percent 42.20%	Total Percent - 100.00%						
145	Gen/Prop Trading - Mid Office	Joint Operating Agreement Labor Hours Ratio	28.7745%	NSPM Average Percent 28.77%	Total Percent - 100.00%						
146	Risk Mgmt - OpCos	Asset/Revenue/Number of Employees	45.0776%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259		
147	Captive Insurance	Asset/Revenue/Number of Employees	45.0776%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259		
161	Corporate Strategy & Bus Dev - Corporate Governance	Asset/Revenue/Number of Employees	40.4599%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPM No. of Empl - 4,661	Total No. of Empl - 9,273		
162	Corp Strategy & Bus Dev - OpCo	Asset/Revenue/Number of Employees	45.0776%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259		
163	LEGAL OpCo Electric	Asset/Revenue/Number of Employees	45.0776%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259		
164	Legal OpCo Gas	Asset/Revenue/Number of Employees	52.4080%	NSPM Assets - \$16,722,524	Total Assets - \$33,542,481	NSPM Revenues - \$5,022,827	Total Revenues - \$10,281,981	NSPM No. of Empl - 4,661	Total No. of Empl - 7,965		
170	Legal	Asset/Revenue/Number of Employees	45.0621%	NSPM Assets - \$16,722,524	Total Assets - \$38,244,299	NSPM Revenues - \$5,022,827	Total Revenues - \$12,214,868	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259		
171	Legal - Corporate Governance	Asset/Revenue/Number of Employees	40.4599%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPM No. of Empl - 4,661	Total No. of Empl - 9,273		
172	Legal - NSPM & NSPW	Asset/Revenue/Number of Employees	87.3597%	NSPM Assets - \$16,722,524	Total Assets - \$18,999,262	NSPM Revenues - \$5,022,827	Total Revenues - \$5,882,711	NSPM No. of Empl - 4,661	Total No. of Empl - 5,256		
173	Legal - NSPM & NSPW Electric	Asset/Revenue/Number of Employees	87.3597%	NSPM Assets - \$16,722,524	Total Assets - \$18,999,262	NSPM Revenues - \$5,022,827	Total Revenues - \$5,882,711	NSPM No. of Empl - 4,661	Total No. of Empl - 5,256		
174	Legal - OpCos	Asset/Revenue/Number of Employees	45.0776%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259		
180	Communications - Corporate Governance	Asset/Revenue/Number of Employees	40.4599%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPM No. of Empl - 4,661	Total No. of Empl - 9,273		
181	Employee Communications	Number of Employees	50.2642%	NSPM No. of Empl - 4,661	Total No. of Empl - 9,273						
182	Xcel Foundation	Asset/Revenue/Number of Employees	40.5122%	NSPM Assets - \$16,722,524	Total Assets - \$51,093,243	NSPM Revenues - \$5,022,827	Total Revenues - \$13,031,643	NSPM No. of Empl - 4,661	Total No. of Empl - 9,273		
184	Branding	Asset/Revenue/Number of Employees	40.5122%	NSPM Assets - \$16,722,524	Total Assets - \$51,093,243	NSPM Revenues - \$5,022,827	Total Revenues - \$13,031,643	NSPM No. of Empl - 4,661	Total No. of Empl - 9,273		
185	Customer Safety Advertising/Information Costs	Number of Customers	35.5399%	NSPM No of Customers - 1,924,212	Total No of Customers - 5,414,231						
189	Human Resources (HR) - Corporate Governance	Asset/Revenue/Number of Employees	40.4599%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPM No. of Empl - 4,661	Total No. of Empl - 9,273		
190	Human Resources (Diversity/Safety/Emp Relations)	Number of Employees	50.3402%	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259						
197	Human Resources - Operating Companies	Number of Employees	50.3402%	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259						
198	Payroll	Number of Employees	50.2642%	NSPM No. of Empl - 4,661	Total No. of Empl - 9,273						
199	Human Resources - Recruitment	Number of Employees	50.3402%	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259						

Northern States Power Company

NSPM

Statistics for Service Company Allocations(as used in the JD Edwards accounting system)

2016 Test Year Budget

Docket No. E002/GR-15-826
Exhibit___(ARD-1), Schedule 5
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Workorder Number	Workorder Title	Allocation Method	2016 NSPM Alloc Percent	Allocation Statistics							
403	Customer Service IT - FERC 903	Number of Customers	35.5399%	NSPM No of Customers - 1,924,212	Total No of Customers - 5,414,231						
405	Customer Service IT FERC 903 - North	Number of Customers	84.0832%	NSPM No of Customers - 1,924,212	Total No of Customers - 2,288,462						
409	Federal Lobbying	Asset/Revenue/Number of Employees	40.5584%	NSPM Assets - \$16,722,524	Total Assets - \$50,882,813	NSPM Revenues - \$5,022,827	Total Revenues - \$13,030,797	NSPM No. of Empl - 4,661	Total No. of Empl - 9,273		
410	Governmental Affairs	Asset/Revenue/Number of Employees	40.5584%	NSPM Assets - \$16,722,524	Total Assets - \$50,882,813	NSPM Revenues - \$5,022,827	Total Revenues - \$13,030,797	NSPM No. of Empl - 4,661	Total No. of Empl - 9,273		
412	Marketing & Sales	Revenue	41.1362%	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242						
413	Payment and Reporting	Invoice Transactions	34.1956%	NSPM Invoice Transactions - 174,724	Total Invoice Transactions - 510,954						
414	Energy Supply Business Resources	MWH Generation	32.1734%	NSPM MWH Generation - 19,500,297	Total MWH Generation - 60,609,980						
415	Energy Markets - Fuel	MWH Generation	32.1734%	NSPM MWH Generation - 19,500,297	Total MWH Generation - 60,609,980						
416	Supply Chain	Asset/Revenue/Number of Employees	45.0776%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259		
417	Rates & Regulation	Revenue	41.1356%	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,427						
418	Rates & Regulation - Electric	Revenue	41.1362%	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242						
423	Customer & Field Operations Constr, Oper & Maint	Delivery Gross Plant	35.5340%	NSPM Delivery Gross Plant - \$7,702,631	Total Delivery Gross Plant - \$21,676,795						
429	Energy Markets - Regulated Trading (Gen Book)	MWH Hours Sold	36.3840%	NSPM MWH Hours Sold - \$37,813,551	Total MWH Hours Sold - \$103,928,959						
430	Energy Supply Asset Management	Asset/Revenue/Number of Employees	45.0776%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259		
431	Energy Markets - Business Services	Asset/Revenue/Number of Employees	45.0776%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259		
435	Customer Care 903	Number of Customers	35.5399%	NSPM No of Customers - 1,924,212	Total No of Customers - 5,414,231						
436	Customer Care 902	Number of Customers	35.4976%	NSPM No of Customers - 1,924,250	Total No of Customers - 5,420,790						
437	Customer Care 901	Number of Customers	35.5399%	NSPM No of Customers - 1,924,212	Total No of Customers - 5,414,231						
439	Customer Care North 903	Number of Customers	84.0832%	NSPM No of Customers - 1,924,212	Total No of Customers - 2,288,462						
440	Utilities Group Administrative & General FERC 921	Electric Transmission Plant/ Electric Distribution Plant/ Gas Transmission Plant/Gas Distribution Plant	35.5340%	NSPM Electric Trans Plant - \$3,110,663	Total Electric Trans Plant - \$7,993,212	NSPM Electric Dist Plant - \$3,560,034	Total Electric Dist Plant - \$9,630,431	NSPM Gas Trans Plant - \$76,036	Total Gas Trans Plant - \$827,800	NSPM Gas Dist Plant - \$955,898	Total Gas Dist Plant - \$3,225,352
441	Distribution Electric FERC 580 (E&S)	Electric Distribution Plant	36.9665%	NSPM Electric Dist Plant - \$3,560,034	Total Electric Dist Plant - \$9,630,431						
442	Transmission Electric FERC 560 (E&S)	Electric Transmission Plant	38.9163%	NSPM Electric Trans Plant - \$3,110,663	Total Electric Trans Plant - \$7,993,212						
443	Distribution Gas FERC 870 (E&S)	Gas Distribution Plant	29.6370%	NSPM Gas Dist Plant - \$955,898	Total Gas Dist Plant - \$3,225,352						
444	Transmission Gas FERC 850 (E&S)	Gas Transmission Plant	9.1853%	NSPM Gas Trans Plant - \$76,036	Total Gas Trans Plant - \$827,800						
445	Distribution Gas FERC 880 (Misc)	Gas Distribution Plant	29.6370%	NSPM Gas Dist Plant - \$955,898	Total Gas Dist Plant - \$3,225,352						
446	Customer Care Low Income Assistance 908	Number of Residential Customers/Number of Calls	39.0318%	NSPM No of Residential Customers - 1,721,397	Total No of Residential Customers - 4,764,999	NSPM No of Calls - 64,331	Total No of Calls - 153,397				
447	Customer Billing FERC 903	Number of Customer Bills	39.8529%	NSPM No of Customers - 1,457,633	Total No of Customers - 3,657,536						
449	Transm Elec 560 NSPM & NSPW	Electric Transmission Plant	77.4636%	NSPM Electric Trans Plant - \$3,110,663	Total Electric Trans Plant - \$4,015,645						
451	Transm Elec FERC 561.5	Electric Transmission Plant	38.9163%	NSPM Electric Trans Plant - \$3,110,663	Total Electric Trans Plant - \$7,993,212						
453	Distribution Elec FERC 586	Electric Distribution Plant	36.9665%	NSPM Electric Dist Plant - \$3,560,034	Total Electric Dist Plant - \$9,630,431						
454	Distribution Gas FERC 878	Gas Distribution Plant	29.6370%	NSPM Gas Dist Plant - \$955,898	Total Gas Dist Plant - \$3,225,352						
455	ES Misc Power Expense Op Co's	MWH Generation	32.1734%	NSPM MWH Generation - 19,500,297	Total MWH Generation - 60,609,980						
456	ES Misc Power Expense North	MWH Generation	93.7591%	NSPM MWH Generation - 19,500,297	Total MWH Generation - 20,798,284						
458	ES Operations Management OPCO's	MWH Generation	32.1734%	NSPM MWH Generation - 19,500,297	Total MWH Generation - 60,609,980						
459	ES Operations Management North	MWH Generation	93.7591%	NSPM MWH Generation - 19,500,297	Total MWH Generation - 20,798,284						
464	ES Environmental Policy & Services OpCo's	Gross Plant Assets	41.1980%	NSPM Gross Plant Assets - \$15,212,780	Total Gross Plant Assets - \$36,926,058						
468	Transmission Elec FERC 566 - Finance Busines Area	Asset/Revenue/Number of Employees	45.0776%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259		
469	Elec Distribution FERC 588 - Finance Busines Area	Asset/Revenue/Number of Employees	45.0776%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259		
470	Gas Distribution FERC 880 - Finance Busines Area	Asset/Revenue/Number of Employees	52.4080%	NSPM Assets - \$16,722,524	Total Assets - \$33,542,481	NSPM Revenues - \$5,022,827	Total Revenues - \$10,281,981	NSPM No. of Empl - 4,661	Total No. of Empl - 7,965		
474	Gas Dist/Elec Dist/Gas Trans Finance FERC 588, 880, 856	Electric Distribution Plant/ Gas Transmission Plant/ Gas Distribution Plant	33.5583%	NSPM Electric Dist Plant - \$3,560,034	Total Electric Dist Plant - \$9,630,431	NSPM Gas Dist Plant - \$955,898	Total Gas Dist Plant - \$3,225,352	NSPM Gas Trans Plant - \$76,036	Total Gas Trans Plant - \$827,800		
500	Business Systems	Number of Computers	58.5524%	NSPM Total Computers - 5,525	Total Total Computers - 9,436						
503	CRS (Customer Resource System)	Number of Meters/Number of Contacts	34.9813%	NSPM No. of Meters - 1,960,709	Total No. of Meters - 5,450,452	NSPM No. of Contacts - 1,989,025	Total No. of Contacts - 5,851,914				
504	Maximo	Number of Maximo Users	32.4772%	NSPM No. of Maximo Users - 708	Total No. of Maximo Users - 2,190						
505	JDE (J.D. Edwards)	Asset/Revenue/Number of Employees	40.4599%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPM No. of Empl - 4,661	Total No. of Empl - 9,273		

Workorder Number	Workorder Title	Allocation Method	2016 NSPM Alloc Percent	Allocation Statistics						
506	GIS (Geographic Information System)	Electric Distribution Plant/ Gas Distribution Plant	33.3018%	NSPM Electric Dist Plant - \$3,560,034	Total Electric Dist Plant - \$9,630,431	NSPM Gas Dist Plant - \$955,898	Total Gas Dist Plant - \$3,225,352			
507	OMS (Outage Management System)	Electric Distribution Plant/ Gas Distribution Plant	33.3018%	NSPM Electric Dist Plant - \$3,560,034	Total Electric Dist Plant - \$9,630,431	NSPM Gas Dist Plant - \$955,898	Total Gas Dist Plant - \$3,225,352			
508	e-Business	Number of Employees	50.3402%	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259					
509	Passport - All Modules	Total AP/ Inventory/ Work Management/ Purchase Transactions	35.8678%	NSPM No. of Passport Transactions - 824,096	Total No. of Passport Transactions - 2,297,588					
510	Passport - Accounts Payable	Accounts Payable Transactions	35.5385%	NSPM No. of AP Transactions - 475,932	Total No. of AP Transactions - 1,339,203					
512	Passport - Work Management	Work Management Transactions	55.5091%	NSPM No. of Work Mgmt Transactions - 107,162	Total No. of Work Mgmt Transactions - 193,053					
513	Passport - Purchasing	Purchasing Transactions	29.3543%	NSPM No. of Purchasing Transactions - 92,673	Total No. of Purchasing Transactions - 315,705					
514	Miscellaneous Applications	Average of all Software Percentages	37.6487%	NSPM Average percent 37.65%	Total Percent - 100.00%					
515	PeopleSoft	Number of Employees	50.2642%	NSPM No. of Empl - 4,661	Total No. of Empl - 9,273					
516	PowerPlant	Total Plant	44.6276%	NSPM Total Plant - \$19,630,031	Total Total Plant - \$43,986,336					
517	GMS (Gas Management System)	Number of Gas Customers (incl Transp Cust)	0.0017%	NSPM Average Gas Customers-incl Transp - 24	Total Average Gas Customers-incl Transp - 1,451,357					
518	MDMS (Monitoring Device Management System)	Number of Meters	35.9733%	NSPM No. of Meters - 1,960,709	Total No. of Meters - 5,450,452					
519	CLQM (Call Logging and Quality Management)	Number of Customers/Number of Contacts	34.7646%	NSPM No of Customers - 1,924,212	Total No of Customers - 5,414,231	NSPM No of Contacts - 1,989,025	Total No. of Contacts - 5,851,914			
520	IVR (Interactive Voice Response)	Number of Contacts	33.9893%	NSPM No. of Contacts - 1,989,025	Total No. of Contacts - 5,851,914					
521	Time/Project Time Reporting System (PTRS)	Number of Employees	50.2642%	NSPM No. of Empl - 4,661	Total No. of Empl - 9,273					
523	Network	Phones/Radios/Computers	53.1057%	NSPM No of Phone Lines - 6,264	Total No of Phone Lines - 10,655	NSPM No of Radios - 2,265	Total No of Radios - 5,396	NSPM Total Computers - 5,525	Total Total Computers - 9,436	
524	DSS (Distributed Systems & Services) Support	Number of Computers	58.5524%	NSPM Total Computers - 5,525	Total Total Computers - 9,436					
525	Utility Innovations	Delivery Gross Plant	35.5340%	NSPM Delivery Gross Plant \$7,702,631	Total Delivery Gross Plant \$21,676,795					
526	EMS-Transmission (Energy Mgmt System-SCADA)	Electric Transmission Plant	38.9163%	NSPM Electric Trans Plant \$3,110,663	Total Electric Trans Plant \$7,993,212					
527	EMS-Distribution (Energy Mgmt System-SCADA)	Electric Distribution Plant	36.9665%	NSPM Electric Dist Plant - \$3,560,034	Total Electric Dist Plant - \$9,630,431					
528	EMS-Shared (Energy Mgmt System-SCADA)	Electric Production Plant/ Electric Transmission Plant/ Electric Distribution Plant	41.7106%	NSPM Electric Trans Plant \$3,110,663	Total Electric Trans Plant \$7,993,212	NSPM Electric Dist Plant - \$3,560,034	Total Electric Dist Plant - \$9,630,431	NSPM Electric Prod Plant - \$7,510,149	Total Electric Prod Plant - \$15,249,263	
531	Gas SCADA	Gas Transmission Plant/ Gas Distribution Plant	19.4112%	NSPM Gas Trans Plant - \$76,036	Total Gas Trans Plant - \$827,800	NSPM Gas Dist Plant - \$955,898	Total Gas Dist Plant - \$3,225,352			
533	CBS/ALS/CFM	Asset/Revenue/Number of Employees	45.0776%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259	
534	CES (Customer & Enterprise Solutions)	Number of - Computers/Customers/Employees	48.1441%	NSPM Total Computers - 5,525	Total No of Computers - 9,436	NSPM No of Customers - 1,924,212	Total No of Customers - 5,414,231	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259	
540	Meter Reading Acquisition System (MRAS)	Number of Meters	35.9733%	NSPM No. of Meters - 1,960,709	Total No. of Meters - 5,450,452					
542	PCI (Power Cost Incorporated)	Asset/Revenue/Number of Employees	45.0776%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259	
544	EAI (Entrprs Applic Integrat)	Average of a Select Set of Software Allocators	38.5798%	NSPM Average percent 38.58%	Total Percent - 100.00%					
549	CFO Systems	Asset/Revenue/Number of Employees	40.4599%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPM No. of Empl - 4,661	Total No. of Empl - 9,273	
550	Human Resources (HR) Systems	Number of Employees	50.3402%	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259					
551	Corporate Systems	Asset/Revenue/Number of Employees	40.4599%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPM No. of Empl - 4,661	Total No. of Empl - 9,273	
552	Security Systems	Number of Employees	50.2642%	NSPM No. of Empl - 4,661	Total No. of Empl - 9,273					
553	Energy Supply Systems	Number of Maximo Users	32.4772%	NSPM No. of Maximo Users - 708	Total No. of Maximo Users - 2,180					
554	Business Objects	Number of Business Object Users	38.8669%	NSPM No. of Business Objects Users - 590	Total No. of Business Objects Users - 1,518					
559	Mobile Computing	Electric Distribution Plant/ Gas Distribution Plant	33.3018%	NSPM Electric Dist Plant - \$3,560,034	Total Electric Dist Plant - \$9,630,431	NSPM Gas Dist Plant - \$955,898	Total Gas Dist Plant - \$3,225,352			
561	Enterprise Continuity	Asset/Revenue/Number of Employees	40.4599%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPM No. of Empl - 4,661	Total No. of Empl - 9,273	
562	Mainframe Charges From IBM	Average of a Select Set of Software Allocators	28.7464%	NSPM Average percent 28.75%	Total Percent - 100.00%					
563	SAP GL	Asset/Revenue/Number of Employees	40.4599%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPM No. of Empl - 4,661	Total No. of Empl - 9,273	
10471	Integrated Talent Management	Number of Employees	50.3402%	NSPM No. of Empl - 4,661	Total No. of Empl - 9,259					
10472	Wind Predictor Enhancement	MWH Hours Sold	38.9116%	NSPM MWH Hours Sold - \$37,813,551	Total MWH Hours Sold - \$97,178,071					
10493	Work and Asset Management Phase 1	Number of Inventory, WM, Purchasing Transactions plus number of Maximo Users	34.4026%	NSPM No. of Inventory Transactions - 148,329	Total No. of Inventory Transactions - 449,627	NSPM No. of Work Mgmt Transactions 107,162	Total No. of Work Mgmt Transactions 193,053	NSPM No. of Purchasing Transactions - 92,673	Total No. of Purchasing Transactions - 315,705	NSPM No. of Maximo Users - 708
10507	Work and Asset Management Phase 2	Number of Inventory, WM, Purchasing Transactions plus number of Maximo Users	34.4026%	NSPM No. of Inventory Transactions - 148,329	Total No. of Inventory Transactions - 449,627	NSPM No. of Work Mgmt Transactions 107,162	Total No. of Work Mgmt Transactions 193,053	NSPM No. of Purchasing Transactions - 92,673	Total No. of Purchasing Transactions - 315,705	NSPM No. of Maximo Users - 708
10530	GL Design, Build Test Deploy	Asset/Revenue/Number of Employees	40.4599%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPM No. of Empl - 4,661	Total No. of Empl - 9,273	
10543	Field Sched & Dispatch	Number of Inventory, WM, Purchasing Transactions plus number of Maximo Users	34.4026%	NSPM No. of Inventory Transactions - 148,329	Total No. of Inventory Transactions - 449,627	NSPM No. of Work Mgmt Transactions 107,162	Total No. of Work Mgmt Transactions 193,053	NSPM No. of Purchasing Transactions - 92,673	Total No. of Purchasing Transactions - 315,705	NSPM No. of Maximo Users - 708

Workorder Number	Workorder Title	Allocation Method	2016 NSPM Alloc Percent	Allocation Statistics							
10544	ER Increased Strategic Sourcing	Number of Inventory, WM, Purchasing Transactions plus number of Maximo Users	34.4026%	NSPM No. of Inventory Transactions - 148,329	Total No. of Inventory Transactions - 449,627	NSPM No. of Work Mgmt Transactions 107,162	Total No. of Work Mgmt Transactions 193,053	NSPM No. of Purchasing Transactions - 92,673	Total No. of Purchasing Transactions - 315,705	NSPM No. of Maximo Users - 708	Total No. of Maximo Users - 2,180
10545	ER Inventory Mgt & Material Flow Optimization	Number of Inventory, WM, Purchasing Transactions plus number of Maximo Users	34.4026%	NSPM No. of Inventory Transactions - 148,329	Total No. of Inventory Transactions - 449,627	NSPM No. of Work Mgmt Transactions 107,162	Total No. of Work Mgmt Transactions 193,053	NSPM No. of Purchasing Transactions - 92,673	Total No. of Purchasing Transactions - 315,705	NSPM No. of Maximo Users - 708	Total No. of Maximo Users - 2,180
10546	ER Procurement Operations Optimization	Number of Inventory, WM, Purchasing Transactions plus number of Maximo Users	34.4026%	NSPM No. of Inventory Transactions - 148,329	Total No. of Inventory Transactions - 449,627	NSPM No. of Work Mgmt Transactions 107,162	Total No. of Work Mgmt Transactions 193,053	NSPM No. of Purchasing Transactions - 92,673	Total No. of Purchasing Transactions - 315,705	NSPM No. of Maximo Users - 708	Total No. of Maximo Users - 2,180
10548	ER Talent Strategy	Number of Inventory, WM, Purchasing Transactions plus number of Maximo Users	34.4026%	NSPM No. of Inventory Transactions - 148,329	Total No. of Inventory Transactions - 449,627	NSPM No. of Work Mgmt Transactions 107,162	Total No. of Work Mgmt Transactions 193,053	NSPM No. of Purchasing Transactions - 92,673	Total No. of Purchasing Transactions - 315,705	NSPM No. of Maximo Users - 708	Total No. of Maximo Users - 2,180
10549	ER Solution Strategy	Number of Inventory, WM, Purchasing Transactions plus number of Maximo Users	34.4026%	NSPM No. of Inventory Transactions - 148,329	Total No. of Inventory Transactions - 449,627	NSPM No. of Work Mgmt Transactions 107,162	Total No. of Work Mgmt Transactions 193,053	NSPM No. of Purchasing Transactions - 92,673	Total No. of Purchasing Transactions - 315,705	NSPM No. of Maximo Users - 708	Total No. of Maximo Users - 2,180
10550	Enterprise Transformation Office	ETO Hours	39.1209%	NSPM ETO Hours - 15,385	Total ETO Hours - 39,328						
10555	WAM- Work and Asset Management Blueprint	Number of Inventory, WM, Purchasing Transactions plus number of Maximo Users	34.4026%	NSPM No. of Inventory Transactions - 148,329	Total No. of Inventory Transactions - 449,627	NSPM No. of Work Mgmt Transactions 107,162	Total No. of Work Mgmt Transactions 193,053	NSPM No. of Purchasing Transactions - 92,673	Total No. of Purchasing Transactions - 315,705	NSPM No. of Maximo Users - 708	Total No. of Maximo Users - 2,180

Workorder Number	Workorder Title	Allocation Method	NSPM Alloc Percent						
110	Executive - Corporate Governance	Asset/Revenue/FTE Labor Hours	39.8635%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPMN FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,956
114	Board of Directors - Corporate Governance	Asset/Revenue/FTE Labor Hours	39.8635%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPMN FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,956
115	Shareholder - Corporate Governance	Asset/Revenue/FTE Labor Hours	39.8635%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPMN FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,956
116	Investor Relations - Corporate Governance	Asset/Revenue/FTE Labor Hours	39.8635%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPMN FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,956
120	Accounting, Reporting, & Taxes	Asset/Revenue/FTE Labor Hours	44.4496%	NSPM Assets - \$16,722,524	Total Assets - \$38,244,299	NSPM Revenues - \$5,022,827	Total Revenues - \$12,214,868	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,943
121	Accounting & Reporting - Corporate Governance	Asset/Revenue/FTE Labor Hours	39.8635%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPMN FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,956
123	Accounting - Operating Companies	Asset/Revenue/FTE Labor Hours	44.4659%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,942
125	Acctg, Rptg, Tax - MN, WI	Asset/Revenue/FTE Labor Hours	86.6013%	NSPM Assets - \$16,722,524	Total Assets - \$18,999,262	NSPM Revenues - \$5,022,827	Total Revenues - \$5,882,711	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 12,879
126	Acctg, Rptg, Tax - MN, WI Elec	Asset/Revenue/FTE Labor Hours	86.6013%	NSPM Assets - \$16,722,524	Total Assets - \$18,999,262	NSPM Revenues - \$5,022,827	Total Revenues - \$5,882,711	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 12,879
127	Acctg, Rptg, Tax - OpCos Elec	Asset/Revenue/FTE Labor Hours	44.4659%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,942
130	Audit Services	Asset/Revenue/FTE Labor Hours	44.4496%	NSPM Assets - \$16,722,524	Total Assets - \$38,244,299	NSPM Revenues - \$5,022,827	Total Revenues - \$12,214,868	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,943
131	Audit Services - Corporate Governance	Asset/Revenue/FTE Labor Hours	39.8635%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPMN FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,956
132	Audit Services - OpCos	Asset/Revenue/FTE Labor Hours	44.4659%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,942
133	Audit Services - OpCos - Elect	Asset/Revenue/FTE Labor Hours	44.4659%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,942
134	Audit Services - OpCos - Gas	Asset/Revenue/FTE Labor Hours	51.7808%	NSPM Assets - \$16,722,524	Total Assets - \$33,542,481	NSPM Revenues - \$5,022,827	Total Revenues - \$10,281,981	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 19,648
135	Capital Asset Acctg	Asset/Revenue/FTE Labor Hours	44.3036%	NSPM Assets - \$16,722,524	Total Assets - \$38,583,119	NSPM Revenues - \$5,022,827	Total Revenues - \$12,226,509	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,950
140	Finance & Treasury	Asset/Revenue/FTE Labor Hours	44.4496%	NSPM Assets - \$16,722,524	Total Assets - \$38,244,299	NSPM Revenues - \$5,022,827	Total Revenues - \$12,214,868	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,943
141	Finance & Treasury - Corporate Governance	Asset/Revenue/FTE Labor Hours	39.8635%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPMN FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,956
142	Risk Management	Asset/Revenue/FTE Labor Hours	44.4496%	NSPM Assets - \$16,722,524	Total Assets - \$38,244,299	NSPM Revenues - \$5,022,827	Total Revenues - \$12,214,868	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,943
143	Risk Management - Corporate Governance	Asset/Revenue/FTE Labor Hours	39.8635%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPMN FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,956
146	Risk Mgmt - OpCos	Asset/Revenue/FTE Labor Hours	44.4659%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,942
147	Captive Insurance	Asset/Revenue/FTE Labor Hours	44.4659%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,942
161	Corporate Strategy & Bus Dev - Corporate Governance	Asset/Revenue/FTE Labor Hours	39.8635%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPMN FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,956
162	Corp Strategy & Bus Dev - OpCo	Asset/Revenue/FTE Labor Hours	44.4659%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,942
163	LEGAL OpCo Electric	Asset/Revenue/FTE Labor Hours	44.4659%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,942
164	Legal OpCo Gas	Asset/Revenue/FTE Labor Hours	51.7808%	NSPM Assets - \$16,722,524	Total Assets - \$33,542,481	NSPM Revenues - \$5,022,827	Total Revenues - \$10,281,981	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 19,648
170	Legal	Asset/Revenue/FTE Labor Hours	44.4496%	NSPM Assets - \$16,722,524	Total Assets - \$38,244,299	NSPM Revenues - \$5,022,827	Total Revenues - \$12,214,868	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,943
171	Legal - Corporate Governance	Asset/Revenue/FTE Labor Hours	39.8635%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPMN FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,956

Workorder Number	Workorder Title	Allocation Method	NSPM Alloc Percent						
172	Legal - NSPM & NSPW	Asset/Revenue/FTE Labor Hours	86.6013%	NSPM Assets - \$16,722,524	Total Assets - \$18,999,262	NSPM Revenues - \$5,022,827	Total Revenues - \$5,882,711	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 12,879
173	Legal - NSPM & NSPW Electric	Asset/Revenue/FTE Labor Hours	86.6013%	NSPM Assets - \$16,722,524	Total Assets - \$18,999,262	NSPM Revenues - \$5,022,827	Total Revenues - \$5,882,711	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 12,879
174	Legal - OpCos	Asset/Revenue/FTE Labor Hours	44.4659%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,942
180	Communications - Corporate Governance	Asset/Revenue/FTE Labor Hours	39.8635%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPMN FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,956
181	Employee Communications	FTE Labor Hours	48.4923%	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,948				
182	Xcel Foundation	Asset/Revenue/FTE Labor Hours	40.5949%	NSPM Assets - \$16,722,524	Total Assets - \$51,093,243	NSPM Revenues - \$5,022,827	Total Revenues - \$13,031,643	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,948
184	Branding	Asset/Revenue/FTE Labor Hours	40.5949%	NSPM Assets - \$16,722,524	Total Assets - \$51,093,243	NSPM Revenues - \$5,022,827	Total Revenues - \$13,031,643	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,948
189	Human Resources (HR) - Corporate Governance	Asset/Revenue/FTE Labor Hours	39.8635%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPMN FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,956
190	Human Resources (Diversity/Safety/Emp Relations)	FTE Labor Hours	48.5050%	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,942				
197	Human Resources - Operating Companies	FTE Labor Hours	48.5050%	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,942				
198	Payroll	FTE Labor Hours	48.4923%	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,948				
199	Human Resources - Recruitment	FTE Labor Hours	48.5050%	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,942				
409	Federal Lobbying	Asset/Revenue/FTE Labor Hours	39.9676%	NSPM Assets - \$16,722,524	Total Assets - \$50,882,813	NSPM Revenues - \$5,022,827	Total Revenues - \$13,030,797	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,948
410	Governmental Affairs	Asset/Revenue/FTE Labor Hours	39.9676%	NSPM Assets - \$16,722,524	Total Assets - \$50,882,813	NSPM Revenues - \$5,022,827	Total Revenues - \$13,030,797	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,948
416	Supply Chain	Asset/Revenue/FTE Labor Hours	44.4659%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,942
430	Energy Supply Asset Management	Asset/Revenue/FTE Labor Hours	44.4659%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,942
431	Energy Markets - Business Services	Asset/Revenue/FTE Labor Hours	44.4659%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,942
468	Transmission Elec FERC 566 - Finance Busines Area	Asset/Revenue/FTE Labor Hours	44.4659%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,942
469	Elec Distribution FERC 588 - Finance Busines Area	Asset/Revenue/FTE Labor Hours	44.4659%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,942
470	Gas Distribution FERC 880 - Finance Busines Area	Asset/Revenue/FTE Labor Hours	51.7808%	NSPM Assets - \$16,722,524	Total Assets - \$33,542,481	NSPM Revenues - \$5,022,827	Total Revenues - \$10,281,981	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 19,648
505	JDE (J.D. Edwards)	Asset/Revenue/FTE Labor Hours	39.8635%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPMN FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,956
508	e-Business	FTE Labor Hours	48.5050%	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,942				
514	Miscellaneous Applications	Average of all Software Percentages	37.3782%	NSPM Average percent 37.38%	Total Percent - 100.00%				
515	PeopleSoft	FTE Labor Hours	48.4923%	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,948				
521	Time/Project Time Reporting System (PTRS)	FTE Labor Hours	48.4923%	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,948				
533	CBS/ALS/CFM	Asset/Revenue/FTE Labor Hours	44.4659%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,942
534	CES (Customer & Enterprise Solutions)	Number of - Computers/Customers, FTE Labor Hours	47.5324%	NSPM Total Computers - 5,525	Total Total Computers - 9,436	NSPM No of Customers - 1,924,212	Total No of Customers - 5,414,231	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,942
542	PCI (Power Cost Incorporated)	Asset/Revenue/FTE Labor Hours	44.4659%	NSPM Assets - \$16,722,524	Total Assets - \$38,217,279	NSPM Revenues - \$5,022,827	Total Revenues - \$12,210,242	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,942

Workorder Number	Workorder Title	Allocation Method	NSPM Alloc Percent						
544	EAI (Entrprs Applic Integrat)	Average of a Select Set of Software Allocators	38.1808%	NSPM Average percent 38.18%	Total Percent - 100.00%				
549	CFO Systems	Asset/Revenue/FTE Labor Hours	39.8635%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPMN FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,956
550	Human Resources (HR) Systems	FTE Labor Hours	48.5050%	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,942				
551	Corporate Systems	Asset/Revenue/FTE Labor Hours	39.8635%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPMN FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,956
552	Security Systems	FTE Labor Hours	48.4923%	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,948				
561	Enterprise Continuity	Asset/Revenue/FTE Labor Hours	39.8635%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPMN FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,956
562	Mainframe Charges From IBM	Average of a Select Set of Software Allocators	28.1558%	NSPM Average percent 28.16%	Total Percent - 100.00%				
563	SAP GL	Asset/Revenue/FTE Labor Hours	39.8635%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPMN FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,956
10471	Integrated Talent Management	FTE Labor Hours	48.5050%	NSPM FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,942				
10530	GL Design, Build Test Deploy	Asset/Revenue/FTE Labor Hours	39.8635%	NSPM Assets - \$16,722,524	Total Assets - \$51,264,981	NSPM Revenues - \$5,022,827	Total Revenues - \$13,047,915	NSPMN FTE Labor Hours - 11,128	Total FTE Labor Hours - 22,956

Impact to NSPM 2016 Test Year for Change in XES Allocations
Using FTE Method Instead of Number of Employees
2016 Budget Test Year

Iteration	Work Order No.	Work Order Title	Allocation Method	Current Method	FTE Method	Variance	XES Total Amount	NSPM Total Company Amount	NSPM Total Company Revised Amount	NSPM Test Year Impact
1	110	Executive - Corporate Governance	Asset/Revenue/Number of Employees	40.4599%	39.8635%	-0.5964%	41,267.698	16,733.283	16,498.626	(246.657)
1	114	Board of Directors - Corporate Governance	Asset/Revenue/Number of Employee	40.4599%	39.8635%	-0.5964%	3,227.778	1,305.956	1,286.705	(19.251)
1	115	Board of Directors - Corporate Governance	Asset/Revenue/Number of Employees	40.4599%	39.8635%	-0.5964%	1,358.045	549.464	541.364	(8.100)
1	116	Shareholder - Corporate Governance	Asset/Revenue/Number of Employees	40.4599%	39.8635%	-0.5964%	1,441.470	583.217	574.620	(8.597)
4	120	Investor Relations - Corporate Governance	Asset/Revenue/Number of Employees	45.0621%	44.4496%	-0.6125%	280.650	117.454	115.858	(1.596)
1	121	Accounting, Reporting, & Taxes	Asset/Revenue/Number of Employees	40.4599%	39.8635%	-0.5964%	15,883.201	6,420.327	6,331.690	(88.637)
7	123	Accounting & Reporting - Corporate Governance	Asset/Revenue/Number of Employees	45.0776%	44.4659%	-0.6117%	11,405.302	5,141.237	5,071.470	(69.767)
10	125	Accounting NSPM & NSPW	Asset/Revenue/Number of Employees	87.3597%	86.6013%	-0.7584%	415.866	363.299	360.145	(3.154)
10	126	Acctg NSPM & NSPW Electric	Asset/Revenue/Number of Employees	87.3597%	86.6013%	-0.7584%	366.749	320.391	317.609	(2.782)
1	127	Accounting OPCos Elec	Asset/Revenue/Number of Employees	45.0776%	44.4659%	-0.6117%	1,950.750	879.351	867.418	(11.933)
4	130	Audit Services	Asset/Revenue/Number of Employees	45.0621%	44.4496%	-0.6125%	1,128	501	500	(1)
1	131	Audit Services - Corporate Governance	Asset/Revenue/Number of Employees	40.4599%	39.8635%	-0.5964%	2,598.046	1,031.167	1,035.672	(15.495)
7	132	AUDIT Serv OPCos	Asset/Revenue/Number of Employees	45.0776%	44.4659%	-0.6117%	249.423	112.434	110.908	(1.526)
7	133	AUDIT OPCos Electric	Asset/Revenue/Number of Employees	45.0776%	44.4659%	-0.6117%	226.632	102.160	100.774	(1.386)
7	134	CA ACCTG	Asset/Revenue/Number of Employees	51.7808%	50.4080%	-0.6272%	89.672	46.995	46.433	(562)
2	135	Finance & Treasury	Asset/Revenue/Number of Employees	44.9211%	44.3036%	-0.6175%	123.931	55.671	54.906	(765)
4	140	Finance & Treasury	Asset/Revenue/Number of Employees	45.0621%	44.4496%	-0.6125%	960	433	427	(6)
1	141	Finance & Treasury - Corporate Governance	Asset/Revenue/Number of Employees	40.4599%	39.8635%	-0.5964%	3,349.991	1,355.403	1,335.424	(19.979)
4	142	Risk Management	Asset/Revenue/Number of Employees	45.0621%	44.4496%	-0.6125%	11,629.859	5,169.426	5,169.426	(71.233)
1	143	Risk Management	Asset/Revenue/Number of Employees	40.4599%	39.8635%	-0.5964%	1,444.203	584.323	575.710	(8.613)
7	146	Risk Management - Corporate Governance	Asset/Revenue/Number of Employees	45.0776%	44.4659%	-0.6117%	2,234.682	1,007.341	993.672	(13.669)
4	147	Risk OPCos	Asset/Revenue/Number of Employees	45.0776%	44.4659%	-0.6117%	218.067	98.308	96.974	(1.334)
1	161	Corporate Strategy & Business Development	Asset/Revenue/Number of Employees	40.4599%	39.8635%	-0.5964%	4,315.246	1,745.944	1,720.208	(25.736)
7	162	Corporate Strategy & Business Development	Asset/Revenue/Number of Employees	45.0776%	44.4659%	-0.6117%	115.900	52.245	51.536	(709)
7	163	Legal - Non-Corporate Governance	Asset/Revenue/Number of Employees	45.0776%	44.4659%	-0.6117%	282.500	127.344	125.616	(1.728)
9	164	Legal - Non-Corporate Governance	Asset/Revenue/Number of Employees	52.4080%	51.7808%	-0.6272%	6.692	3.507	3.465	(42)
4	170	Legal OPCo Gas	Asset/Revenue/Number of Employees	45.0621%	44.4496%	-0.6125%	890.604	401.325	395.870	(5.455)
1	171	Legal	Asset/Revenue/Number of Employees	40.4599%	39.8635%	-0.5964%	11,294.446	4,569.721	4,502.361	(67.360)
10	172	Legal - NSPM and NSPW	Asset/Revenue/Number of Employees	87.3597%	86.6013%	-0.7584%	520.000	454.270	450.327	(3.943)
10	173	Legal - NSPM and NSPW Electric	Asset/Revenue/Number of Employees	87.3597%	86.6013%	-0.7584%	200.000	174.719	173.203	(1.516)
7	174	LEGAL OPCos	Asset/Revenue/Number of Employees	45.0776%	44.4659%	-0.6117%	140.500	63.334	62.475	(859)
1	180	Communications - Corporate Governance	Asset/Revenue/Number of Employees	40.4599%	39.8635%	-0.5964%	4,074.239	1,648.433	1,624.134	(24.299)
9	181	Employee Communications	Number of Employees	50.2642%	49.4923%	-1.7719%	1,995.884	952.951	919.359	(33.592)
5	182	Xcel Foundation	Asset/Revenue/Number of Employees	40.5122%	40.5949%	0.0827%	4,014.697	1,786.870	1,790.518	3.648
5	184	Branding	Asset/Revenue/Number of Employees	40.5122%	40.5949%	0.0827%	8,441.833	3,419.972	3,426.954	6.982
1	189	Human Resources (HR) - Corporate Governance	Asset/Revenue/Number of Employees	40.4599%	39.8635%	-0.5964%	7,980.043	3,228.718	3,181.125	(47.593)
6	190	Human Resources (Diversity/Safety/Emp Relations)	Number of Employees	50.3402%	48.5050%	-1.8352%	11,695.387	5,867.345	5,853.446	(13.899)
6	197	Human Resources - Energy Markets	Number of Employees	50.3402%	48.5050%	-1.8352%	3,626.839	1,855.758	1,759.198	(96.560)
3	198	Human Resources - Operating Companies	Number of Employees	50.2642%	48.4923%	-1.7719%	1,581.145	794.750	766.734	(28.016)
6	199	Payroll	Number of Employees	50.3402%	48.5050%	-1.8352%	2,696.862	1,357.605	1,308.113	(49.492)
8	409	Human Resources - Recruitment	Asset/Revenue/Number of Employees	40.5584%	39.9676%	-0.5908%	2,385.124	967.368	953.277	(14.091)
8	410	Federal Lobbying (FERC 42640)	Asset/Revenue/Number of Employees	40.5584%	39.9676%	-0.5908%	2,402.061	974.238	960.046	(14.192)
7	416	Governmental Affairs	Asset/Revenue/Number of Employees	45.0776%	44.4659%	-0.6117%	48.361	21.800	21.504	(296)
7	430	Supply Chain	Asset/Revenue/Number of Employees	45.0776%	44.4659%	-0.6117%	760.327	342.737	338.086	(4.651)
7	431	Energy Supply Asset Management	Asset/Revenue/Number of Employees	45.0776%	44.4659%	-0.6117%	8,430.625	3,800.323	3,748.753	(51.570)
7	468	Energy Markets - Business Services	Asset/Revenue/Number of Employees	45.0776%	44.4659%	-0.6117%	907.417	409.042	403.491	(5.551)
7	469	Transm Elec FERC 566	Asset/Revenue/Number of Employees	45.0776%	44.4659%	-0.6117%	88.781	31.005	30.584	(421)
9	470	Elec Dist FERC 588	Asset/Revenue/Number of Employees	52.4080%	51.7808%	-0.6272%	55.408	29.038	28.691	(347)
1	505	JDE (J.D. Edwards)	Asset/Revenue/Number of Employees	40.4599%	39.8635%	-0.5964%	85.175	34.462	33.954	(508)
6	508	e-Business	Number of Employees	48.5050%	45.3402%	-1.8352%	941.645	474.026	456.745	(17.281)
11	514	Miscellaneous Applications	Average of all Software Percentages	37.6487%	37.3762%	-0.2705%	25,145.756	9,467.050	9,399.031	(68.019)
3	515	PeopleSoft	Number of Employees	50.2642%	48.4923%	-1.7719%	1,051.509	528.533	509.901	(18.632)
3	521	Time/PTRS	Number of Employees	50.2642%	48.4923%	-1.7719%	123.215	61.933	59.750	(2.183)
7	533	CBS/ALS/CFM	Asset/Revenue/Number of Employees	45.0776%	44.4659%	-0.6117%	150.336	67.768	66.848	(920)
13	534	CES (Customer & Enterprise Solutions)	Number of Computers/Number of Customers/Number of Employees	48.1441%	47.5324%	-0.6117%	396	191	188	(3)
7	542	PCI	Asset/Revenue/Number of Employees	45.0776%	44.4659%	-0.6117%	296.941	133.854	132.037	(1.817)
12	544	Enterprise Application Integration/Enterprise Service Bus (EAI/ESB)	Average of a select set of Software Allocators	38.5798%	38.1808%	-0.3990%	72,407.880	27,934.815	27,645.908	(288.907)
1	549	CFO Systems	Asset/Revenue/Number of Employees	40.4599%	39.8635%	-0.5964%	2,175.791	880.323	867.346	(12.977)
6	550	Human Resources (HR) Systems	Number of Employees	50.3402%	48.5050%	-1.8352%	1,210.690	609.464	587.245	(22.219)
1	551	Corporate Systems	Asset/Revenue/Number of Employees	40.4599%	39.8635%	-0.5964%	9,356.080	3,380.861	3,331.026	(49.835)
3	562	Security Systems	Number of Employees	50.2642%	48.4923%	-1.7719%	3,191.603	1,604.234	1,547.682	(56.552)
1	561	Mainframe Changes from IBM	Average of a Selected Set of Software Allocators	39.8635%	38.8594%	-0.9964%	421.422	170.507	167.994	(2.513)
14	562	Enterprise Continuity	Asset/Revenue/Number of Employees	28.1568%	28.1568%	-0.9906%	3,219.037	925.357	906.346	(19.011)
1	563	SAP GL	Asset/Revenue/Number of Employees	39.8635%	38.8594%	-0.9964%	7,512.271	3,039.458	2,994.654	(44.804)

NSPM Total Company Amount	NSPM Total Company Revised Amount	NSPM Test Year Impact
126,438,582	124,579,970	(1,858,612)

E/G Allocator		Customer Allocator		E/G Allocator		Customer Allocator	
92.24%		87.35%	6.27%	6.38%		7.76%	89.33%
							10.67%
NSPM Elec		ND Elec		NSPM Gas		ND Gas	
MN Elec		SD Elec		MN Gas		ND Gas	
(227,509)	(198,725)	(14,268)	(14,516)	(19,149)	(17,105)	(2,044)	(2,044)
(17,756)	(15,510)	(1,114)	(1,133)	(1,494)	(1,335)	(159)	(159)
(7,471)	(6,526)	(469)	(477)	(629)	(562)	(67)	(67)
(7,930)	(6,927)	(497)	(506)	(687)	(596)	(71)	(71)
(1,472)	(1,286)	(92)	(94)	(124)	(111)	(13)	(13)
(87,373)	(76,319)	(5,480)	(5,575)	(7,354)	(6,569)	(785)	(785)
(64,350)	(56,208)	(4,036)	(4,106)	(5,416)	(4,838)	(578)	(578)
(2,909)	(2,541)	(182)	(186)	(245)	(219)	(26)	(26)
(2,566)	(2,241)	(161)	(164)	(216)	(193)	(23)	(23)
(11,007)	(9,614)	(690)	(702)	(926)	(827)	(99)	(99)
(7)	(6)	0	0	(1)	(1)	0	0
(14,292)	(12,484)	(896)	(912)	(1,203)	(1,075)	(128)	(128)
(1,408)	(1,230)	(88)	(90)	(118)	(105)	(13)	(13)
(1,279)	(1,117)	(80)	(82)	(108)	(96)	(12)	(12)
(519)	(453)	(33)	(33)	(44)	(39)	(5)	(5)
(706)	(617)	(44)	(45)	(59)	(53)	(6)	(6)
(5)	(4)	0	0	0	0	0	0
(18,428)	(16,096)	(1,156)	(1,176)	(1,551)	(1,385)	(166)	(166)
(85,703)	(67,390)	(4,121)	(4,192)	(5,330)	(4,940)	(590)	(590)
(7,944)	(6,939)	(498)	(507)	(669)	(598)	(71)	(71)
(12,608)	(11,013)	(791)	(804)	(1,061)	(948)	(113)	(113)
(1,231)	(1,075)	(77)	(79)	(104)	(93)	(11)	(11)
(23,738)	(20,735)	(1,499)	(1,515)	(1,998)	(1,785)	(213)	(213)
(654)	(571)	(41)	(42)	(55)	(49)	(6)	(6)
(1,594)	(1,392)	(100)	(102)	(134)	(120)	(14)	(14)
(39)	(34)	(2)	(2)	(3)	(3)	0	0
(5,031)	(4,394)	(316)	(321)	(423)	(378)	(45)	(45)
(62,131)	(54,270)	(3,897)	(3,964)	(5,229)	(4,671)	(558)	(558)
(3,637)	(3,177)	(228)	(232)	(306)	(273)	(33)	(33)
(1,399)	(1,222)	(88)	(89)	(118)	(105)	(13)	(13)
(792)	(692)	(50)	(51)	(67)	(60)	(7)	(7)
(22,413)	(19,577)	(1,406)	(1,430)	(1,886)	(1,685)	(201)	(201)
(30,985)	(27,065)	(1,943)	(1,977)	(2,306)	(2,030)	(276)	(276)
3,365	2,939	211	215	283	253	30	30
6,440	5,625	404	411	542	484	58	58
(43,898)	(38,344)	(2,753)	(2,801)	(3,695)	(3,301)	(394)	(394)
(15,831)	(13,624)	(1,273)	(1,288)	(1,606)	(1,434)	(172)	(172)
(61,303)	(53,626)	(3,917)	(3,917)	(5,167)	(4,616)	(551)	(551)
(25,841)	(22,572)	(1,621)	(1,649)	(2,175)	(1,943)	(232)	(232)
(45,650)	(39,874)	(2,863)	(2,913)	(3,842)	(3,432)	(410)	(410)
(12,997)	(11,353)	(815)	(829)	(1,094)	(977)	(117)	(117)
(40,961)	(35,434)	(3,521)	(3,535)	(4,522)	(3,984)	(451)	(451)
(273)	(238)	(17)	(17)	(23)	(21)	(2)	(2)
(4,260)	(3,747)	(269)	(274)	(361)	(322)	(39)	(39)
(47,567)	(41,549)	(2,983)	(3,035)	(4,004)	(3,577)	(427)	(427)
(5,120)	(4,472)	(321)	(327)	(431)	(385)	(46)	(46)
(309)	(269)	(24)	(25)	(33)	(29)	(4)	(4)
(320)	(280)	(20)	(20)	(27)	(24)	(3)	(3)
(468)	(409)	(29)	(30)	(39)	(35)	(4)	(4)
(15,939)	(13,922)	(1,000)	(1,017)	(1,342)	(1,199)	(143)	(143)
(62,739)	(54,011)	(3,935)	(4,003)	(5,281)	(4,717)	(564)	(564)
(1,181)	(1,014)	(78)	(78)	(1,066)	(946)	(118)	(118)
(2,013)	(1,758)	(126)	(128)	(169)	(151)	(18)	(18)
(848)	(741)	(53)	(54)	(71)	(63)	(8)	(8)
(2)	(2)	0	0	0	0	0	0
(1,676)	(1,464)	(105)	(107)	(141)	(126)	(15)	(15)
(266,479)	(232,764)	(16,712)	(17,002)	(22,429)	(20,035)	(2,394)	(2,394)
(11,969)	(10,455)	(751)	(764)	(1,007)	(900)	(107)	(107)
(20,494)	(17,901)	(1,285)	(1,308)	(1,725)	(1,541)	(184)	(184)
(45,967)	(40,151)	(2,883)	(2,933)	(3,869)	(3,456)	(413)	(413)
(45,967)	(40,151)	(2,883)	(2,933)	(3,869)	(3,456)	(413)	(413)
(2,318)	(2,025)	(145)	(148)	(195)	(174)	(21)	(21)
(17,535)	(15,316)	(1,100)	(1,119)	(1,476)	(1,318)	(158)	(158)
(41,325)	(36,097)	(2,592)	(2,637)	(3,478)	(3,107)	(371)	(371)
(1,714,321)	(1,497,425)	(107,513)	(109,382)	(144,288)	(128,891)	(15,397)	(15,397)

THIS FILING IS

Item 1: ☒ An Initial (Original) Submission OR ☐ Resubmission No. _____

FERC FINANCIAL REPORT

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

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

Exact Legal Name of Respondent (Company)

Xcel Energy Services Inc.

Year of Report

Dec 31, 2014

GENERAL INSTRUCTIONS FOR FILING FERC FORM NO. 60**I. Purpose**

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

II. Who Must Submit

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

III. How to Submit

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

IV. When to Submit

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

V. Preparation

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

VI. Time Period

This report covers the entire calendar year.

VII. Whole Dollar Usage

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

VIII. Accurateness

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

IX. Applicability

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

X. Date Format

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

XI. Number Format

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

XII. Required Entries

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

XIII. Prior Year References

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

XIV. Where to Send Comments on Public Reporting Burden

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

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

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

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

And to:

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

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

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

FERC FORM NO. 60
ANNUAL REPORT FOR SERVICE COMPANIES

IDENTIFICATION		
01 Exact Legal Name of Respondent Xcel Energy Services Inc.		02 Year of Report Dec 31, <u>2014</u>
03 Previous Name (If name changed during the year)		04 Date of Name Change / /
05 Address of Principal Office at End of Year (Street, City, State, Zip Code) 414 Nicollet Mall, Minneapolis, MN 55402	06 Name of Contact Person Jeffrey S. Savage	
07 Title of Contact Person Senior Vice President and Controller	08 Address of Contact Person 414 Nicollet Mall Minneapolis, MN 55402	
09 Telephone Number of Contact Person (612) 330-5658	10 E-mail Address of Contact Person Jeffrey.S.Savage@xcelenergy.com	
11 This Report is: (1) ☒ An Original (2) ☐ A Resubmission	12 Resubmission Date (Month, Day, Year) / /	
13 Date of Incorporation 04/02/1997	14 If Not Incorporated, Date of Organization / /	
15 State or Sovereign Power Under Which Incorporated or Organized DELAWARE		
16 Name of Principal Holding Company Under Which Reporting Company is Organized: Xcel Energy, Inc.		
CORPORATE OFFICER CERTIFICATION		
The undersigned officer certifies that: I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.		
17 Name of Signing Officer Jeffrey S. Savage	19 Signature of Signing Officer Jeffrey S. Savage	20 Date Signed (Month, Day, Year) 04/29/2015
18 Title of Signing Officer Senior Vice President and Controller		

Name of Respondent Xcel Energy Services Inc.		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, <u>2014</u>
List of Schedules and Accounts					
1. Enter in Column (c) the terms "None" or "Not Applicable" as appropriate, where no information or amounts have been reported for certain pages.					
Line No.	Description (a)	Page Reference (b)	Remarks (c)		
1	Schedule I - Comparative Balance Sheet	101-102			
2	Schedule II - Service Company Property	103	None		
3	Schedule III - Accumulated Provision for Depreciation and Amortization of Service Company Property	104	None		
4	Schedule IV - Investments	105			
5	Schedule V - Accounts Receivable from Associate Companies	106			
6	Schedule VI - Fuel Stock Expenses Undistributed	107	None		
7	Schedule VII - Stores Expense Undistributed	108	None		
8	Schedule VIII - Miscellaneous Current and Accrued Assets	109	None		
9	Schedule IX - Miscellaneous Deferred Debits	110			
10	Schedule X - Research, Development, or Demonstration Expenditures	111	None		
11	Schedule XI - Proprietary Capital	201			
12	Schedule XII - Long-Term Debt	202	None		
13	Schedule XIII - Current and Accrued Liabilities	203			
14	Schedule XIV - Notes to Financial Statements	204			
15	Schedule XV - Comparative Income Statement	301-302			
16	Schedule XVI - Analysis of Charges for Service - Associate and Nonassociate Companies	303-306			
17	Schedule XVII - Analysis of Billing - Associate Companies (Account 457)	307			
18	Schedule XVIII - Analysis of Billing - Non-Associate Companies (Account 458)	308	None		
21	Schedule XIX - Miscellaneous General Expenses - Account 930.2	307			
23	Schedule XX - Organization Chart	401			
24	Schedule XXI - Methods of Allocation	402			

Name of Respondent Xcel Energy Services Inc.		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, <u>2014</u>
Schedule I - Comparative Balance Sheet					
1. Give balance sheet of the Company as of December 31 of the current and prior year.					
Line No.	Account Number (a)	Description (b)	Reference Page No. (c)	As of Dec 31 Current (d)	As of Dec 31 Prior (e)
1		Service Company Property			
2	101	Service Company Property	103		
3	101.1	Property Under Capital Leases	103		
4	106	Completed Construction Not Classified			
5	107	Construction Work In Progress	103		
6		Total Property (Total Of Lines 2-5)			
7	108	Less: Accumulated Provision for Depreciation of Service Company Property	104		
8	111	Less: Accumulated Provision for Amortization of Service Company Property			
9		Net Service Company Property (Total of Lines 6-8)			
10		Investments			
11	123	Investment In Associate Companies	105		
12	124	Other Investments	105	6,589,508	6,134,405
13	128	Other Special Funds	105		
14		Total Investments (Total of Lines 11-13)		6,589,508	6,134,405
15		Current And Accrued Assets			
16	131	Cash			
17	134	Other Special Deposits			
18	135	Working Funds			
19	136	Temporary Cash Investments		751,001	897,914
20	141	Notes Receivable			
21	142	Customer Accounts Receivable			
22	143	Accounts Receivable		1,902,326	698,801
23	144	Less: Accumulated Provision for Uncollectible Accounts			
24	146	Accounts Receivable From Associate Companies	106	104,265,553	100,506,915
25	152	Fuel Stock Expenses Undistributed	107		
26	154	Materials And Supplies			4,790
27	163	Stores Expense Undistributed	108		
28	165	Prepayments		48,523,263	40,739,946
29	171	Interest And Dividends Receivable			
30	172	Rents Receivable			
31	173	Accrued Revenues			
32	174	Miscellaneous Current and Accrued Assets			
33	175	Derivative Instrument Assets	109		
34	176	Derivative Instrument Assets – Hedges			
35		Total Current and Accrued Assets (Total of Lines 16-34)		155,442,143	142,848,366
36		Deferred Debits			
37	181	Unamortized Debt Expense			
38	182.3	Other Regulatory Assets			
39	183	Preliminary Survey And Investigation Charges			
40	184	Clearing Accounts			
41	185	Temporary Facilities			
42	186	Miscellaneous Deferred Debits		233,053,457	192,900,572
43	188	Research, Development, or Demonstration Expenditures	110		
44	189	Unamortized loss on reacquired debt	111		
45	190	Accumulated Deferred Income Taxes		51,479,619	48,601,592
46		Total Deferred Debits (Total of Lines 37-45)		284,533,076	241,502,164
47		TOTAL ASSETS AND OTHER DEBITS (TOTAL OF LINES 9, 14, 35 and 46)		446,564,727	390,484,935

Name of Respondent Xcel Energy Services Inc.		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, <u>2014</u>
Schedule I - Comparative Balance Sheet (continued)					
Line No.	Account Number (a)	Description (b)	Reference Page No. (c)	As of Dec 31 Current (d)	As of Dec 31 Prior (e)
48		Proprietary Capital			
49	201	Common Stock Issued	201	10	10
50	204	Preferred Stock Issued	201		
51	211	Miscellaneous Paid-In-Capital	201	(312,346)	(312,374)
52	215	Appropriated Retained Earnings	201		
53	216	Unappropriated Retained Earnings	201		
54	219	Accumulated Other Comprehensive Income	201	(9,038,523)	(8,944,855)
55		Total Proprietary Capital (Total of Lines 49-54)		(9,350,859)	(9,257,219)
56		Long-Term Debt			
57	223	Advances From Associate Companies	202		
58	224	Other Long-Term Debt	202		
59	225	Unamortized Premium on Long-Term Debt			
60	226	Less: Unamortized Discount on Long-Term Debt-Debit			
61		Total Long-Term Debt (Total of Lines 57-60)			
62		Other Non-current Liabilities			
63	227	Obligations Under Capital Leases-Non-current			
64	228.2	Accumulated Provision for Injuries and Damages		500,000	800,000
65	228.3	Accumulated Provision For Pensions and Benefits		173,020,850	139,056,663
66	230	Asset Retirement Obligations			
67		Total Other Non-current Liabilities (Total of Lines 63-66)		173,520,850	139,856,663
68		Current and Accrued Liabilities			
69	231	Notes Payable			
70	232	Accounts Payable		111,464,398	118,445,815
71	233	Notes Payable to Associate Companies	203	74,600,000	59,000,000
72	234	Accounts Payable to Associate Companies	203		
73	236	Taxes Accrued			6,468,285
74	237	Interest Accrued			
75	241	Tax Collections Payable		2,401,401	2,270,603
76	242	Miscellaneous Current and Accrued Liabilities	203	8,082,452	3,419,459
77	243	Obligations Under Capital Leases – Current			
78	244	Derivative Instrument Liabilities			
79	245	Derivative Instrument Liabilities – Hedges			
80		Total Current and Accrued Liabilities (Total of Lines 69-79)		196,548,251	189,604,162
81		Deferred Credits			
82	253	Other Deferred Credits		35,611,432	29,060,784
83	254	Other Regulatory Liabilities			
84	255	Accumulated Deferred Investment Tax Credits			
85	257	Unamortized Gain on Reacquired Debt			
86	282	Accumulated deferred income taxes-Other property		3,161,662	3,263,436
87	283	Accumulated deferred income taxes-Other		47,073,391	37,957,109
88		Total Deferred Credits (Total of Lines 82-87)		85,846,485	70,281,329
89		TOTAL LIABILITIES AND PROPRIETARY CAPITAL (TOTAL OF LINES 55, 61, 67, 80, AND 88)		446,564,727	390,484,935

Name of Respondent Xcel Energy Services Inc.		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Resubmission Date (Mo, Da, Yr) / /		Year/Period of Report Dec 31, <u>2014</u>	
Schedule II - Service Company Property							
1. Provide an explanation of Other Changes recorded in Column (f) considered material in a footnote. 2. Describe each construction work in progress on lines 18 through 30 in Column (b).							
Line No.	Acct # (a)	Title of Account (b)	Balance at Beginning of Year (c)	Additions (d)	Retirements or Sales (e)	Other Changes (f)	Balance at End of Year (g)
1	301	Organization					
2	303	Miscellaneous Intangible Plant					
3	306	Leasehold Improvements					
4	389	Land and Land Rights					
5	390	Structures and Improvements					
6	391	Office Furniture and Equipment					
7	392	Transportation Equipment					
8	393	Stores equipment					
9	394	Tools, Shop and Garage Equipment					
10	395	Laboratory Equipment					
11	396	Power Operated Equipment					
12	397	Communications Equipment					
13	398	Miscellaneous Equipment					
14	399	Other Tangible Property					
15	399.1	Asset Retirement Costs					
16		Total Service Company Property (Total of Lines 1-15)					
17	107	Construction Work in Progress:					
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31		Total Account 107 (Total of Lines 18-30)					
32		Total (Lines 16 and Line 31)					

Name of Respondent	This Report Is:	Resubmission Date	Year/Period of Report
Xcel Energy Services Inc.	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) / /	Dec 31, <u>2014</u>

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

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

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

Name of Respondent Xcel Energy Services Inc.		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, <u>2014</u>
Schedule IV – Investments					
1. For other investments (Account 124) and other special funds (Account128), in a footnote state each investment separately, with description including the name of issuing company, number of shares held or principal investment amount. 2. For temporary cash investments (Account 136), list each investment separately in a footnote. 3. Investments less than \$50,000 may be grouped, showing the number of items in each group.					
Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)	
1	123	Investment In Associate Companies			
2	124	Other Investments	6,134,404	6,589,508	
3	128	Other Special Funds			
4	136	Temporary Cash Investments	897,913	751,001	
5		(Total of Lines 1-4)	7,032,317	7,340,509	

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year of Report 2014
Xcel Energy Services Inc.			
FOOTNOTE DATA			

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

FERC Account 124-Other Investments

Funding vehicles for key man insurance and deferred compensation obligations.					
2014	Pacific Life Insurance Co.	Security Life Insurance	Prudential Insurance Co.	Hartford Insurance Co.	Total
Officer Survivor Benefit (OSB) Cash Surrender Value (CSV)				629,492	\$629,492
Premiums	261,502		51,636		\$313,138
CSV	9,083,313	397,303	911,813		\$10,392,429
Loans	-4,430,663	-314,888			(\$4,745,551)
Total	\$4,914,152	\$82,416	\$963,449	\$629,492	\$6,589,508

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

FERC Account 136-Temporary Cash Investments:

The full amount represents the December 31, 2014 excess cash balance, which was held in a temporary cash investment.

Name of Respondent Xcel Energy Services Inc.		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, <u>2014</u>
Schedule V – Accounts Receivable from Associate Companies					
1. List the accounts receivable from each associate company. 2. If the service company has provided accommodation or convenience payments for associate companies, provide in a separate footnote a listing of total payments for each associate company.					
Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)	
1	146	Accounts Receivable From Associate Companies			
2		Associate Company:			
3		Northern States Power Company, a Minnesota corporation (NSP-Minnesota)	44,413,796	46,973,762	
4		Public Service Company of Colorado, a Colorado corporation (PSCo)	36,423,193	40,147,114	
5		Southwestern Public Service Company, a New Mexico corporation (SPS)	14,305,566	13,721,537	
6		Northern States Power Company, a Wisconsin corporation (NSP-Wisconsin)	6,387,900	4,501,118	
7		Xcel Energy Transmission Holding Company, LLC		102,207	
8		Eloigne Company	30,873	101,743	
9		e-prime, inc.	16,121	50,469	
10		Xcel Energy WYCO Inc.	25,851	41,060	
11		Xcel Energy Southwest Transmission Company, LLC		29,909	
12		Xcel Energy Wholesale Group Inc.	6,287	13,164	
13		1480 Welton, Inc.	4,784	5,350	
14		Chippewa and Flambeau Improvement Company	3,677	4,604	
15		WestGas InterState, Inc.	2,436	4,558	
16		NCE Communications, Inc.	2,725	3,629	
17		Seren Innovations, Inc.	5,593	2,973	
18		P.S.R. Investments, Inc.	2,448	2,666	
19		Clearwater Investments, Inc.	1,517	2,146	
20		Xcel Energy Retail Holdings Inc.	1,933	2,052	
21		Xcel Energy Performance Contracting Inc.	1,287	1,384	
22		Reddy Kilowatt Corporation	690	1,351	
23		Xcel Energy Ventures Inc.	1,242	1,337	
24		Xcel Energy International Inc.	2,642	1,258	
25		Xcel Energy Markets Holdings Inc.	894	1,208	
26		Xcel Energy Communications Group Inc.	1,058	1,163	
27		Quixx Corporation	1,599	1,012	
28		NSP Lands, Inc.	330	702	
29		United Power & Land Company	339	539	
30		Xcel Energy Transmission Development Company, LLC		(99,998)	
31		Xcel Energy Inc.	(1,137,866)	(1,354,464)	
32				0	
33					
34					
35					
36					
37					
38					
39					
40	Total		100,506,915	104,265,553	

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year of Report
Xcel Energy Services Inc.			2014
FOOTNOTE DATA			

Schedule Page: 106 Line No.: 30 Column: d

Xcel Energy Transmission Development Company, LLC:

The credit balance represents funds that were set aside in anticipation of expenses that did not come in until after the first of the year. This created an over-funded state at year end.

Schedule Page: 106 Line No.: 31 Column: d

Xcel Energy Inc.:

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

Schedule Page: 106 Line No.: 32 Column: d

2014 CONVENIENCE PAYMENTS

NSP-Minnesota	78,011,668
PSCo	48,721,014
NSP-Wisconsin	18,110,413
SPS	17,740,814
Xcel Energy Inc.	2,201,862
e-prime, inc.	96,487
Xcel Energy Wholesale Group Inc.	53,462
1480 Welton, Inc.	41,389
WestGas InterState, Inc.	12,821
Chippewa and Flambeau Improvement Company	5,313
Xcel Energy Performance Contracting Inc.	3,845
Quixx Corporation	1,988
Seren Innovations, Inc.	342
Xcel Energy Transmission Development Company, LLC	176
Xcel Energy Southwest Transmission Company, LLC	88
Xcel Energy Transmission Holding Company, LLC	88
Reddy Kilowatt Corporation	50
	165,001,821

Name of Respondent Xcel Energy Services Inc.		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, 2014
Schedule VI – Fuel Stock Expenses Undistributed					
1. List the amount of labor in Column (c) and expenses in Column (d) incurred with respect to fuel stock expenses during the year and indicate amount attributable to each associate company. 2. In a separate footnote, describe in a narrative the fuel functions performed by the service company.					
Line No.	Account Number (a)	Title of Account (b)	Labor (c)	Expenses (d)	Total (e)
1	152	Fuel Stock Expenses Undistributed			
2		Associate Company:			
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	Total				

Name of Respondent	This Report Is:	Resubmission Date	Year/Period of Report
Xcel Energy Services Inc.	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) / /	Dec 31, <u>2014</u>

Schedule VII – Stores Expense Undistributed

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

Line No.	Account Number (a)	Title of Account (b)	Labor (c)	Expenses (d)	Total (e)
1	163	Stores Expense Undistributed			
2		Associate Company:			
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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25					
26					
27					
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29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	Total				

Name of Respondent Xcel Energy Services Inc.		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, <u>2014</u>
Schedule VIII - Miscellaneous Current and Accrued Assets					
1. Provide detail of items in this account. Items less than \$50,000 may be grouped, showing the number of items in each group.					
Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)	
1	174	Miscellaneous Current and Accrued Assets			
2		Item List:			
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
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26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	Total				

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Name of Respondent Xcel Energy Services Inc.		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, 2014
Schedule X - Research, Development, or Demonstration Expenditures					
1. Describe each material research, development, or demonstration project that incurred costs by the service corporation during the year. Items less than \$50,000 may be grouped, showing the number of items in each group.					
Line No.	Account Number (a)	Title of Account (b)	Amount (c)		
1	188	Research, Development, or Demonstration Expenditures			
2		Project List:			
3					
4					
5					
6					
7					
8					
9					
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11					
12					
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31					
32					
33					
34					
35					
36					
37					
38					
39					
40	Total				

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FERC FORM NO. 60 (REVISED 12-07) Page 202

Name of Respondent Xcel Energy Services Inc.		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, <u>2014</u>
Schedule XIII – Current and Accrued Liabilities					
1. Provide the balance of notes and accounts payable to each associate company (Accounts 233 and 234). 2. Give description and amount of miscellaneous current and accrued liabilities (Account 242). Items less than \$50,000 may be grouped, showing the number of items in each group.					
Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)	
1	233	Notes Payable to Associates Companies	59,000,000	74,600,000	
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24	234	Accounts Payable to Associate Companies			
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41	242	Miscellaneous Current and Accrued Liabilities	3,419,459	8,082,452	
42					
43					
44					
45					
46					
47					
48					
49					
50		(Total)	62,419,459	82,682,452	

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year of Report 2014
Xcel Energy Services Inc.			
FOOTNOTE DATA			

Schedule Page: 203 Line No.: 1 Column: d**FERC Account 233-Notes Payable to Associate Company:**

The 2014 balance represents the intercompany borrowings with Xcel Energy Inc.

Schedule Page: 203 Line No.: 41 Column: d**FERC Account 242-Miscellaneous Current and Accrued Liabilities:**

The 2014 balance represents the current benefit obligation for a non-qualified pension plan and retiree medical.

Non-qualified pension plan	\$4,459,993
Retiree Medical	<u>113,000</u>
Total	<u>\$4,662,993</u>

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year of Report 2014
Xcel Energy Services Inc.			
Schedule XIV- Notes to Financial Statements			

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

ANNUAL REPORT OF XCEL ENERGY SERVICES INC.

For the Years Ended December 31, 2014 and 2013

Schedule XIV - NOTES TO FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

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

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

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

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

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

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

Leases — XES evaluates a variety of contracts for lease classification at inception, including rental arrangements for office space, vehicles and equipment. Contracts determined to contain a lease because of per unit pricing that is other than fixed or market price,

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Xcel Energy Services Inc.			2014
Schedule XIV- Notes to Financial Statements			

terms regarding the use of a particular asset, and other factors are evaluated further to determine if the arrangement is a capital lease.

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

Cash and Cash Equivalents — XES considers investments in certain instruments with a remaining maturity of three months or less at the time of purchase, to be cash equivalents.

Inventory — All inventory is recorded at average cost.

Accounts Receivable — Accounts receivable are stated at the actual billed amount.

Subsequent Events — Management has evaluated the impact of events occurring after Dec. 31, 2014 up to Feb. 20, 2015, the date Xcel Energy's GAAP financial statements were issued and has updated such evaluation for disclosure purposes through the date of filing this report. These statements contain all necessary adjustments and disclosures resulting from these evaluations.

2. Common Stock

XES has authorized the issuance of common stock.

Common Shares Authorized	Par Value
1,000	\$ 0.01

At Dec. 31, 2014 and 2013, all shares of common stock were issued and held by Xcel Energy.

3. Borrowings and Other Financing Instruments

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

(Amounts in Thousands of Dollars, Except Interest Rates)	Twelve Months Ended Dec. 31, 2014	Twelve Months Ended Dec. 31, 2013
Borrowing limit.....	\$ 200,000	\$ 200,000
Intercompany borrowings outstanding at period end.....	74,600	59,000
Average amount outstanding.....	102,684	105,730
Maximum amount outstanding.....	169,000	170,200
Weighted average interest rate, computed on a daily basis.....	0.37 %	0.30 %
Weighted average interest rate at period end.....	0.40	0.24

Xcel Energy has established a utility money pool arrangement with NSP-Minnesota, PSCo and SPS and received required regulatory approvals. The utility money pool, administered by XES, allows for short-term investments in NSP-Minnesota, PSCo and SPS from Xcel Energy at market-based interest rates. NSP-Minnesota, PSCo and SPS may also borrow from the utility money pool. The utility money pool arrangement does not allow Xcel Energy to borrow from NSP-Minnesota, PSCo and SPS.

4. Commitments and Contingencies

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Xcel Energy Services Inc.			
Schedule XIV- Notes to Financial Statements			

Leases — The Company leases a variety of facilities used in the normal course of business. The majority of the operating leases are under a leasing program that has initial noncancelable terms of one year, while the remaining leases have various terms. These leases may be renewed or replaced. No material restrictions exist in these leasing agreements concerning dividends, additional debt, or further leasing. Total expenses under operating lease obligations for XES were approximately \$17.5 million and \$16.9 million in 2014 and 2013, respectively.

Future commitments under operating leases are as follows:

(Thousands of Dollars)	Total Operating Leases
2015	\$ 17,948
2016	18,199
2017	17,579
2018	16,483
2019	16,385
Thereafter	128,773

Technology Agreements — XES has a contract that extends through June 2019 with International Business Machines Corp. (IBM) for information technology services. The contract is cancelable at the Company's option, although the Company would be obligated to pay 50 percent of the contract value for early termination. The Company capitalized or expensed \$111.3 million and \$90.3 million associated with the IBM contract in 2014 and 2013, respectively.

XES' contract with Accenture for information technology services extends through January 2017. The contract is cancelable at the Company's option, although there are financial penalties for early termination. The Company capitalized or expensed \$27.3 million and \$23.7 million associated with the Accenture contract in 2014 and 2013, respectively.

Committed minimum payments under these obligations are as follows:

(Millions of Dollars)	IBM Agreement	Accenture Agreement
2015	\$ 33.0	\$ 9.0
2016	31.9	8.9
2017	32.0	-
2018	31.5	-
2019	15.7	-
Thereafter	-	-

5. Benefit Plans and Other Postretirement Benefits

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

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

Level 1 — Quoted prices are available in active markets for identical assets as of the reporting date. The types of

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year of Report
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Schedule XIV- Notes to Financial Statements			

assets included in Level 1 are highly liquid and actively traded instruments with quoted prices.

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

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

Pension Benefits

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

In addition to the qualified pension plans, Xcel Energy maintains a supplemental executive retirement plan (SERP) and a nonqualified pension plan. The SERP is maintained for certain executives that were participants in the plan in 2008, when the SERP was closed to new participants. The nonqualified pension plan provides unfunded, nonqualified benefits for compensation that is in excess of the limits applicable to the qualified pension plans. The total obligations of the SERP and nonqualified plan as of Dec. 31, 2014 and 2013 for XES were \$31.7 million and \$22.9 million, respectively. In 2014 and 2013, XES recognized net benefit cost for financial reporting for the SERP and nonqualified plans of \$3.2 million and \$5.1 million, respectively. Benefits for these unfunded plans are paid out of Xcel Energy and XES' consolidated operating cash flows.

Xcel Energy and XES base their investment-return assumption on expected long-term performance for each of the investment types included in its pension asset portfolio. Xcel Energy and XES consider the historical returns achieved by its asset portfolio over the past 20-year or longer period, as well as the long-term return levels projected and recommended by investment experts. The pension cost determination assumes a forecasted mix of investment types over the long-term. Investment returns were above the assumed level of 7.05 percent in 2014 and below the assumed level of 6.88 percent in 2013. Xcel Energy and XES continually review their pension assumptions. In 2015, Xcel Energy and XES will use an investment return assumption of 7.09 percent.

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

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

	2014	2013
Domestic and international equity securities.....	37 %	30 %
Long-duration fixed income and interest rate swap securities.....	27	33
Short-to-intermediate fixed income securities.....	13	15
Alternative investments	21	20
Cash.....	2	2
Total.....	100 %	100 %

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

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Schedule XIV- Notes to Financial Statements			

Pension Plan Assets

The following tables present, for each of the fair value hierarchy levels, Xcel Energy's pension plan assets that are measured at fair value as of Dec. 31, 2014 and 2013:

(Thousands of Dollars)	Dec. 31, 2014			
	Level 1	Level 2	Level 3	Total
Cash equivalents	\$ 193,141	\$ -	\$ -	\$ 193,141
Derivatives	-	1,590	-	1,590
Government securities	-	439,186	-	439,186
Corporate bonds	-	318,161	-	318,161
Asset-backed securities	-	3,759	-	3,759
Mortgage-backed securities	-	11,047	-	11,047
Common stock	102,667	-	-	102,667
Private equity investments	-	-	151,871	151,871
Commingled funds	-	1,826,420	-	1,826,420
Real estate	-	-	54,657	54,657
Securities lending collateral obligation and other	-	(18,728)	-	(18,728)
Total	<u>\$ 295,808</u>	<u>\$ 2,581,435</u>	<u>\$ 206,528</u>	<u>\$ 3,083,771</u>

(Thousands of Dollars)	Dec. 31, 2013			
	Level 1	Level 2	Level 3	Total
Cash equivalents	\$ 109,700	\$ -	\$ -	\$ 109,700
Derivatives	-	29,759	-	29,759
Government securities	-	230,212	-	230,212
Corporate bonds	-	547,715	-	547,715
Asset-backed securities	-	6,754	-	6,754
Mortgage-backed securities	-	15,025	-	15,025
Common stock	99,346	-	-	99,346
Private equity investments	-	-	152,849	152,849
Commingled funds	-	1,769,076	-	1,769,076
Real estate	-	-	47,553	47,553
Securities lending collateral obligation and other	-	2,151	-	2,151
Total	<u>\$ 209,046</u>	<u>\$ 2,600,692</u>	<u>\$ 200,402</u>	<u>\$ 3,010,140</u>

The following tables present the changes in Level 3 pension plan assets for the years ended Dec. 31, 2014 and 2013:

(Thousands of Dollars)	Jan. 1, 2014	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances, and Settlements, Net	Transfers Out of Level 3	Dec. 31, 2014
Private equity investments	\$ 152,849	\$ 25,694	\$ (17,573)	\$ (9,099)	\$ -	\$ 151,871
Real estate	47,553	3,569	(2,443)	5,978	-	54,657
Total	<u>\$ 200,402</u>	<u>\$ 29,263</u>	<u>\$ (20,016)</u>	<u>\$ (3,121)</u>	<u>\$ -</u>	<u>\$ 206,528</u>

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Schedule XIV- Notes to Financial Statements			

(Thousands of Dollars)	Jan. 1, 2013	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances, and Settlements, Net	Transfers Out of Level 3 ^(a)	Dec. 31, 2013
Asset-backed securities	\$ 14,639	\$ -	\$ -	\$ -	\$ (14,639)	\$ -
Mortgage-backed securities	39,904	-	-	-	(39,904)	-
Private equity investments	158,498	22,058	(24,335)	(3,372)	-	152,849
Real estate	64,597	(2,659)	8,690	9,317	(32,392)	47,553
Total	<u>\$ 277,638</u>	<u>\$ 19,399</u>	<u>\$ (15,645)</u>	<u>\$ 5,945</u>	<u>\$ (86,935)</u>	<u>\$ 200,402</u>

(a) Transfers out of Level 3 into Level 2 were principally due to diminished use of unobservable inputs that were previously significant to these fair value measurements and were subsequently sold during 2013.

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

(Thousands of Dollars)	2014	2013
Accumulated Benefit Obligation at Dec. 31	\$ 3,545,928	\$ 3,282,651
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	\$ 3,440,704	\$ 3,639,530
Service cost	88,342	96,282
Interest cost	156,619	140,690
Plan amendments	-	(4,120)
Actuarial loss (gain)	342,826	(153,338)
Benefit payments	(281,739)	(278,340)
Obligation at Dec. 31	<u>\$ 3,746,752</u>	<u>\$ 3,440,704</u>
(Thousands of Dollars)	2014	2013
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	\$ 3,010,140	\$ 2,943,783
Actual return on plan assets	224,808	152,259
Employer contributions	130,562	192,438
Benefit payments	(281,739)	(278,340)
Fair value of plan assets at Dec. 31	<u>\$ 3,083,771</u>	<u>\$ 3,010,140</u>
Funded Status of Plans at Dec. 31:		
Funded status ^(a)	\$ (662,981)	\$ (430,564)

(a) Amounts recognized in accumulated provision for pensions and benefits on Xcel Energy's balance sheet

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(Thousands of Dollars)

	2014	2013
XES Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	\$ 210,390	\$ 175,181
Prior service cost	1,478	1,723
Total	<u>\$ 211,868</u>	<u>\$ 176,904</u>

(Thousands of Dollars)

	2014	2013
XES Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Miscellaneous deferred debits	\$ 200,624	\$ 165,851
Accumulated deferred income taxes	4,386	4,314
Net-of-tax accumulated other comprehensive income	6,858	6,739
Total	<u>\$ 211,868</u>	<u>\$ 176,904</u>

XES accumulated provision for pensions and benefits	\$ 119,136	\$ 88,082
Measurement date	Dec. 31, 2014	Dec. 31, 2013

Significant Assumptions Used to Measure Benefit Obligations:

	2014	2013
Discount rate for year-end valuation	4.11 %	4.75 %
Expected average long-term increase in compensation level	3.75	3.75
Mortality table	RP 2014	RP 2000

Mortality — In 2014, the Society of Actuaries published a new mortality table and projection scale that increased the overall life expectancy of males and females. Xcel Energy has reviewed its own population through a credibility analysis and adopted the RP 2014 table with modifications based on its population and specific experience.

Cash Flows — Cash funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the funding requirements of income tax and other pension-related regulations. Required contributions were made in 2013 through 2015 to meet minimum funding requirements.

Total voluntary and required pension funding contributions across all four of Xcel Energy's pension plans were as follows:

- \$90.0 million in January 2015;
- \$130.6 million in 2014; and
- \$192.4 million in 2013.

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

Plan Amendments — In 2014, there were no plan amendments made which affected the projected benefit obligation. The 2013 decrease of the projected benefit obligation for plan amendments was due to fully insuring the long-term disability benefit for NSP-Minnesota and NSP-Wisconsin bargaining participants. This decrease was partially offset by an increase to the projected benefit obligation resulting from a change in the discount rate basis for lump sum conversion of annuities for participants in the Xcel Energy Pension Plan.

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

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(Thousands of Dollars)

	2014	2013
Service cost	\$ 88,342	\$ 96,282
Interest cost	156,619	140,690
Expected return on plan assets	(207,205)	(198,452)
Amortization of prior service (credit) cost	(1,746)	5,871
Amortization of net loss	116,762	144,151
Net periodic pension cost	152,772	188,542
Costs not recognized due to effects of regulation	(26,315)	(36,724)
Net benefit cost recognized for financial reporting	<u>\$ 126,457</u>	<u>\$ 151,818</u>

XES:

Net periodic pension cost	\$ 26,989	\$ 33,394

Significant Assumptions Used to Measure Costs:

Discount rate	4.75 %	4.00 %
Expected average long-term increase in compensation level	3.75	3.75
Expected average long-term rate of return on assets	7.05	6.88

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Pension costs include an expected return impact for the current year that may differ from actual investment performance in the plan. The return assumption used for 2015 pension cost calculations is 7.09 percent. The pension cost calculation uses a market-related valuation of pension assets. Xcel Energy, including XES, uses a calculated value method to determine the market-related value of the plan assets. The market-related value is determined by adjusting the fair market value of assets at the beginning of the year to reflect the investment gains and losses (the difference between the actual investment return and the expected investment return on the market-related value) during each of the previous five years at the rate of 20 percent per year. As these differences between actual investment returns and the expected investment returns are incorporated into the market-related value, the differences are recognized in pension cost over the expected average remaining years of service for active employees.

Xcel Energy, which includes XES, also maintains noncontributory, defined benefit supplemental retirement income plans for certain qualifying executive personnel. Benefits for these unfunded plans are paid out of operating cash flows.

Defined Contribution Plans

Xcel Energy, which includes XES, maintains 401(k) and other defined contribution plans that cover substantially all employees. Xcel Energy's total contributions were approximately \$32.4 million in 2014 and \$30.3 million in 2013. XES' portion of those contributions was approximately \$8.3 million in 2014 and \$7.5 million in 2013.

Postretirement Health Care Benefits

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

In 1993, Xcel Energy and XES adopted accounting guidance regarding other non-pension postretirement benefits and elected to amortize the unrecognized accumulated postretirement benefit obligation (APBO) on a straight-line basis over 20 years.

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

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

	2014		2013	
Domestic and international equity securities.....	25	%	41	%
Short-to-intermediate fixed income securities.....	57		40	
Alternative investments	13		13	
Cash.....	5		6	
Total.....	100	%	100	%

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

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The following tables present, for each of the fair value hierarchy levels, Xcel Energy's postretirement benefit plan assets that are measured at fair value as of Dec. 31, 2014 and 2013:

(Thousands of Dollars)	Dec. 31, 2014			
	Level 1	Level 2	Level 3	Total
Cash equivalents ^(a)	\$ 26,324	\$ -	\$ -	\$ 26,324
Derivatives	-	186	-	186
Government securities	-	48,584	-	48,584
Insurance contracts	-	50,351	-	50,351
Corporate bonds.....	-	54,207	-	54,207
Asset-backed securities	-	3,619	-	3,619
Mortgage-backed securities	-	11,250	-	11,250
Commingled funds	-	282,378	-	282,378
Other	-	(1,841)	-	(1,841)
Total.....	\$ 26,324	\$ 448,734	\$ -	\$ 475,058

(Thousands of Dollars)	Dec. 31, 2013			
	Level 1	Level 2	Level 3	Total
Cash equivalents ^(a)	\$ 20,438	\$ -	\$ -	\$ 20,438
Derivatives	-	(414)	-	(414)
Government securities	-	58,421	-	58,421
Insurance contracts	-	52,808	-	52,808
Corporate bonds.....	-	51,861	-	51,861
Asset-backed securities	-	3,358	-	3,358
Mortgage-backed securities	-	24,246	-	24,246
Commingled funds	-	298,258	-	298,258
Other	-	(16,940)	-	(16,940)
Total.....	\$ 20,438	\$ 471,598	\$ -	\$ 492,036

(a) Includes restricted cash of \$1.0 million and \$0.7 million at Dec. 31, 2014 and 2013, respectively.

For the year ended Dec. 31, 2014 there were no assets transferred in or out of Level 3. The following table presents the changes in Xcel Energy's Level 3 postretirement benefit plan assets for the year ended Dec. 31, 2013:

(Thousands of Dollars)	Jan. 1, 2013	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances, and Settlements, Net	Transfers Out of Level 3 ^(a)	Dec. 31, 2013
Asset-backed securities	\$ 757	\$ -	\$ -	\$ -	\$ (757)	\$ -
Mortgage-backed securities	39,958	-	-	-	(39,958)	-
Total.....	\$ 40,715	\$ -	\$ -	\$ -	\$ (40,715)	\$ -

(a) Transfers out of Level 3 into Level 2 were principally due to diminished use of unobservable inputs that were previously significant to these fair value measurements and were subsequently sold during 2013.

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

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(Thousands of Dollars)

	2014	2013
Change in Projected Benefit Obligation:		
Obligation at Jan. 1.....	\$ 731,428	\$ 851,952
Service cost.....	3,457	4,079
Interest cost.....	34,028	32,141
Medicare subsidy reimbursements.....	1,861	1,197
Plan amendments.....	-	(14,571)
Plan participants' contributions.....	7,148	9,580
Actuarial gain.....	(81,699)	(103,359)
Benefit payments.....	(53,354)	(49,591)
Obligation at Dec. 31.....	<u>\$ 642,869</u>	<u>\$ 731,428</u>

(Thousands of Dollars)

	2014	2013
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1.....	\$ 492,036	\$ 480,842
Actual return on plan assets.....	12,083	33,644
Plan participants' contributions.....	7,148	9,580
Employer contributions.....	17,145	17,561
Benefit payments.....	(53,354)	(49,591)
Fair value of plan assets at Dec. 31.....	<u>\$ 475,058</u>	<u>\$ 492,036</u>

(Thousands of Dollars)

	2014	2013
Funded Status of Plans at Dec. 31:		
Funded status.....	<u>\$ (167,811)</u>	<u>\$ (239,392)</u>
Miscellaneous deferred debits.....	1,014	-
Accumulated provision for pensions and benefits.....	(168,825)	(239,392)
Net postretirement amounts recognized on balance sheet.....	<u>\$ (167,811)</u>	<u>\$ (239,392)</u>

(Thousands of Dollars)

	2014	2013
XES Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss.....	\$ 20,035	\$ 21,978
Prior service credit.....	(3,810)	(4,359)
Total.....	<u>\$ 16,225</u>	<u>\$ 17,619</u>

(Thousands of Dollars)

	2014	2013
XES Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Miscellaneous deferred debits.....	\$ 13,723	\$ 14,986
Accumulated deferred income taxes.....	976	1,028
Net-of-tax accumulated other comprehensive income.....	1,526	1,605
Total.....	<u>\$ 16,225</u>	<u>\$ 17,619</u>
XES accumulated provision for pensions and benefits.....	\$ 29,759	\$ 30,911
Measurement date.....	Dec. 31, 2014	Dec. 31, 2013

Significant Assumptions Used to Measure Benefit Obligations:

Discount rate for year-end valuation.....	4.08 %	4.82 %
Mortality table.....	RP 2014	RP 2000
Health care costs trend rate - initial.....	6.50 %	7.00 %

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Effective Jan. 1, 2015, the initial medical trend rate was decreased from 7.0 percent to 6.5 percent. The ultimate trend assumption remained at 4.5 percent. The period until the ultimate rate is reached is four years. Xcel Energy and XES base their medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost increases experienced by Xcel Energy's retiree medical plan.

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

(Thousands of Dollars)	One Percentage Point	
	Increase	Decrease
APBO	\$ 66,034	\$ (55,588)
Service and interest components	4,432	(3,640)

Cash Flows — The postretirement health care plans have no funding requirements under income tax and other retirement-related regulations other than fulfilling benefit payment obligations, when claims are presented and approved under the plans. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities, as discussed previously. Xcel Energy, which includes XES, contributed \$17.1 million during 2014 and \$17.6 million during 2013 and expects to contribute approximately \$12.8 million during 2015.

Plan Amendments — In 2014, there were no plan amendments made which affected the benefit obligation. The 2013 decrease of the projected Xcel Energy postretirement health and welfare benefit obligation for plan amendments is due to changes in the participant co-pay structure for certain retiree groups.

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

(Thousands of Dollars)	2014	2013
Service cost	\$ 3,457	\$ 4,079
Interest cost	34,028	32,141
Expected return on plan assets	(33,954)	(33,011)
Amortization of transition obligation	-	825
Amortization of prior service credit	(10,688)	(12,501)
Amortization of net loss	11,740	22,325
Net periodic postretirement benefit cost	<u>\$ 4,583</u>	<u>\$ 13,858</u>
XES:		
Net periodic postretirement benefit cost recognized	2,279	2,644
	<u>2014</u>	<u>2013</u>
Significant Assumptions Used to Measure Costs:		
Discount rate	4.82 %	4.10 %
Expected average long-term rate of return on assets	7.17	7.11

Projected Benefit Payments

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

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(Thousands of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
2015	\$ 247,479	\$ 48,398	\$ 2,670	\$ 45,728
2016	269,953	48,665	2,836	45,829
2017	260,182	48,519	3,005	45,514
2018	267,406	48,977	3,170	45,807
2019	269,809	48,461	3,327	45,134
2020-2024	1,352,192	230,692	18,721	211,971

6. Income Taxes

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

(Thousands of Dollars)	2014	2013
Current federal tax (benefit) expense	\$ (5,495)	\$ 1,574
Current state tax expense	869	1,055
Deferred federal tax expense (benefit)	5,998	(1,085)
Deferred state tax expense (benefit)	192	(143)
Total income tax expense	<u>\$ 1,564</u>	<u>\$ 1,401</u>

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

	2014	2013
Federal statutory rate	35 %	35 %
Increases (decreases) in tax from:		
State income taxes, net of federal income tax benefit	44	42
Non-deductible executive compensation	12	20
Non-deductible business meals	14	15
Insurance fund income	(8)	(11)
Resolution of income tax audits and other	2	(1)
Other	1	-
Effective income tax rate	<u>100 %</u>	<u>100 %</u>

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

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(Thousands of Dollars)	2014	2013
Deferred tax liabilities:		
Employee benefits	\$ 43,120	\$ 34,669
Service contracts	3,266	2,440
Differences between book and taxbases of property	3,162	3,263
Other	687	849
Total deferred tax liabilities	<u>\$ 50,235</u>	<u>\$ 41,221</u>
Deferred tax assets:		
Employee benefits	\$ 50,714	\$ 47,751
Other	766	851
Total deferred tax assets	<u>\$ 51,480</u>	<u>\$ 48,602</u>
Net deferred tax asset	<u>\$ (1,245)</u>	<u>\$ (7,381)</u>

7. Financial Instruments

As of Dec. 31, 2014 and 2013, there were no financial instruments for which the carrying amount did not equal fair value.

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Schedule XV- Comparative Income Statement					
Line No.	Account Number (a)	Title of Account (b)	Current Year (c)	Prior Year (d)	
1		SERVICE COMPANY OPERATING REVENUES			
2	400	Service Company Operating Revenues	1,162,105,356	971,841,682	
3		SERVICE COMPANY OPERATING EXPENSES			
4	401	Operation Expenses	634,012,457	602,273,314	
5	402	Maintenance Expenses	19,183,582	15,077,233	
6	403	Depreciation Expenses			
7	403.1	Depreciation Expense for Asset Retirement Costs			
8	404	Amortization of Limited-Term Property			
9	405	Amortization of Other Property			
10	407.3	Regulatory Debits			
11	407.4	Regulatory Credits			
12	408.1	Taxes Other Than Income Taxes, Operating Income	16,696,150	16,033,618	
13	409.1	Income Taxes, Operating Income	6,599,348	3,888,097	
14	410.1	Provision for Deferred Income Taxes, Operating Income			
15	411.1	Provision for Deferred Income Taxes – Credit , Operating Income		(360)	
16	411.4	Investment Tax Credit, Service Company Property			
17	411.6	Gains from Disposition of Service Company Plant			
18	411.7	Losses from Disposition of Service Company Plant			
19	411.10	Accretion Expense			
20	412	Costs and Expenses of Construction or Other Services	475,293,658	328,405,522	
21	416	Costs and Expenses of Merchandising, Jobbing, and Contract Work			
22		TOTAL SERVICE COMPANY OPERATING EXPENSES (Total of Lines 4-21)	1,151,785,195	965,677,424	
23		NET SERVICE COMPANY OPERATING INCOME (Total of Lines 2 less 22)	10,320,161	6,164,258	
24		OTHER INCOME			
25	418.1	Equity in Earnings of Subsidiary Companies			
26	419	Interest and Dividend Income	56,144	254,038	
27	419.1	Allowance for Other Funds Used During Construction			
28	421	Miscellaneous Income or Loss	(34,394)	20,062	
29	421.1	Gain on Disposition of Property			
30		TOTAL OTHER INCOME (Total of Lines 25-29)	21,750	274,100	
31		OTHER INCOME DEDUCTIONS			
32	421.2	Loss on Disposition of Property			
33	425	Miscellaneous Amortization			
34	426.1	Donations	8,293,170	1,305,245	
35	426.2	Life Insurance	(307,031)	(411,252)	
36	426.3	Penalties	20,824	6,216	
37	426.4	Expenditures for Certain Civic, Political and Related Activities	3,461,115	3,764,328	
38	426.5	Other Deductions	3,472,372	3,689,148	
39		TOTAL OTHER INCOME DEDUCTIONS (Total of Lines 32-38)	14,940,450	8,353,685	
40		TAXES APPLICABLE TO OTHER INCOME AND DEDUCTIONS			

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Schedule XV- Comparative Income Statement (continued)					
Line No.	Account Number (a)	Title of Account (b)	Current Year (c)	Prior Year (d)	
41	408.2	Taxes Other Than Income Taxes, Other Income and Deductions			
42	409.2	Income Taxes, Other Income and Deductions	(11,225,632)	(1,259,164)	
43	410.2	Provision for Deferred Income Taxes, Other Income and Deductions	6,190,565	(1,228,026)	
44	411.2	Provision for Deferred Income Taxes – Credit, Other Income and Deductions			
45	411.5	Investment Tax Credit, Other Income Deductions			
46		TOTAL TAXES APPLICABLE TO OTHER INCOME AND DEDUCTIONS (Total of Lines 41-45)	(5,035,067)	(2,487,190)	
47		INTEREST CHARGES			
48	427	Interest on Long-Term Debt			
49	428	Amortization of Debt Discount and Expense			
50	429	(less) Amortization of Premium on Debt- Credit			
51	430	Interest on Debt to Associate Companies	435,844	569,658	
52	431	Other Interest Expense	684	2,205	
53	432	(less) Allowance for Borrowed Funds Used During Construction-Credit			
54		TOTAL INTEREST CHARGES (Total of Lines 48-53)	436,528	571,863	
55		NET INCOME BEFORE EXTRAORDINARY ITEMS (Total of Lines 23, 30, minus 39, 46, and 54)			
56		EXTRAORDINARY ITEMS			
57	434	Extraordinary Income			
58	435	(less) Extraordinary Deductions			
59		Net Extraordinary Items (Line 57 less Line 58)			
60	409.4	(less) Income Taxes, Extraordinary			
61		Extraordinary Items After Taxes (Line 59 less Line 60)			
62		NET INCOME OR LOSS/COST OF SERVICE (Total of Lines 55-61)			

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FOOTNOTE DATA			

Schedule Page: 301 Line No.: 35 Column: c**FERC Account 426.2-Life Insurance:**

Cash surrender value of policies	\$(406,505)
Premiums	<u>99,475</u>
Total	<u>\$(307,031)</u>

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

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Line No.	Account Number	Title of Account	Associate Company Direct Cost	Associate Company Indirect Cost	Associate Company Total Cost	Nonassociate Company Direct Cost	Nonassociate Company Indirect Cost	Nonassociate Company Total Cost
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
35	517-525	Total Nuclear Power Generation Operation Expenses	5,364,432		5,364,432			
36	528-532	Total Nuclear Power Generation Maintenance Expenses	16,465		16,465			
37	535-540.1	Total Hydraulic Power Generation Operation Expenses	501,451	200,769	702,220			
38	541-545.1	Total Hydraulic Power Generation Maintenance Expenses	111,520	6,639	118,159			
39	546-550.1	Total Other Power Generation Operation Expenses	1,705,597	866,379	2,571,976			
40	551-554.1	Total Other Power Generation Maintenance Expenses	576,218	48,386	624,604			
41	555-557	Total Other Power Supply Operation Expenses	9,238,454	1,668,633	10,907,087			
42	560	Operation Supervision and Engineering	8,188,024	7,133,422	15,321,446			
43	561.1	Load Dispatch-Reliability	55,937		55,937			
44	561.2	Load Dispatch-Monitor and Operate Transmission System	4,661,786	4,220,975	8,882,761			
45	561.3	Load Dispatch-Transmission Service and Scheduling	48,570		48,570			
46	561.4	Scheduling, System Control and Dispatch Services						
47	561.5	Reliability Planning and Standards Development	315,574	74,260	389,834			
48	561.6	Transmission Service Studies	32,974		32,974			
49	561.7	Generation Interconnection Studies	112,495		112,495			
50	561.8	Reliability Planning and Standards Development Services	4,438		4,438			
51	562	Station Expenses (Major Only)	1,125,333		1,125,333			
52	563	Overhead Line Expenses (Major Only)	1,367,611		1,367,611			
53	564	Underground Line Expenses (Major Only)						
54	565	Transmission of Electricity by Others (Major Only)	22		22			
55	566	Miscellaneous Transmission Expenses (Major Only)	7,685,882	598,272	8,284,154			
56	567	Rents	1,370,541		1,370,541			
57	567.1	Operation Supplies and Expenses (Nonmajor Only)						
58		Total Transmission Operation Expenses	24,969,187	12,026,929	36,996,116			
59	568	Maintenance Supervision and Engineering (Major Only)	7,709		7,709			
60	569	Maintenance of Structures (Major Only)						
61	569.1	Maintenance of Computer Hardware						
62	569.2	Maintenance of Computer Software						
63	569.3	Maintenance of Communication Equipment						
64	569.4	Maintenance of Miscellaneous Regional Transmission Plant						
65	570	Maintenance of Station Equipment (Major Only)	63,988		63,988			
66	571	Maintenance of Overhead Lines (Major Only)	322,144		322,144			
67	572	Maintenance of Underground Lines (Major Only)						
68	573	Maintenance of Miscellaneous Transmission Plant (Major Only)	144,480		144,480			

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Line No.	Account Number	Title of Account	Associate Company Direct Cost	Associate Company Indirect Cost	Associate Company Total Cost	Nonassociate Company Direct Cost	Nonassociate Company Indirect Cost	Nonassociate Company Total Cost
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
69	574	Maintenance of Transmission Plant (Nonmajor Only)						
70		Total Transmission Maintenance Expenses	538,321		538,321			
71	575.1-575.8	Total Regional Market Operation Expenses	833,589		833,589			
72	576.1-576.5	Total Regional Market Maintenance Expenses						
73	580-589	Total Distribution Operation Expenses	12,060,973	7,476,040	19,537,013			
74	590-598	Total Distribution Maintenance Expenses	1,469,590		1,469,590			
75		Total Electric Operation and Maintenance Expenses	576,816,399	51,100,610	627,917,009			
76	700-798	Production Expenses (Provide selected accounts in a footnote)	191,241		191,241			
77	800-813	Total Other Gas Supply Operation Expenses	734,439		734,439			
78	814-826	Total Underground Storage Operation Expenses	5,151		5,151			
79	830-837	Total Underground Storage Maintenance Expenses						
80	840-842.3	Total Other Storage Operation Expenses	17,808		17,808			
81	843.1-843.9	Total Other Storage Maintenance Expenses	379		379			
82	844.1-846.2	Total Liquefied Natural Gas Terminaling and Processing Operation Expenses						
83	847.1-847.8	Total Liquefied Natural Gas Terminaling and Processing Maintenance Expenses						
84	850	Operation Supervision and Engineering	669,314	279,531	948,845			
85	851	System Control and Load Dispatching.	13,975	1,106,214	1,120,189			
86	852	Communication System Expenses						
87	853	Compressor Station Labor and Expenses	7,855		7,855			
88	854	Gas for Compressor Station Fuel						
89	855	Other Fuel and Power for Compressor Stations						
90	856	Mains Expenses	23,280		23,280			
91	857	Measuring and Regulating Station Expenses	198		198			
92	858	Transmission and Compression of Gas By Others						
93	859	Other Expenses	44,617	1,466	46,083			
94	860	Rents	101,330		101,330			
95		Total Gas Transmission Operation Expenses	860,569	1,387,211	2,247,780			
96	861	Maintenance Supervision and Engineering						
97	862	Maintenance of Structures and Improvements						
98	863	Maintenance of Mains	102,567		102,567			
99	864	Maintenance of Compressor Station Equipment	85		85			
100	865	Maintenance of Measuring And Regulating Station Equipment	271,055		271,055			
101	866	Maintenance of Communication Equipment	4,579	11,315	15,894			
102	867	Maintenance of Other Equipment						
103		Total Gas Transmission Maintenance Expenses	378,286	11,315	389,601			
104	870-881	Total Distribution Operation Expenses	4,697,922	9,014,646	13,712,568			

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Name of Respondent Xcel Energy Services Inc.		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, <u>2014</u>
Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies (continued)					
Line No.	Account Number (a)	Title of Account (b)	Total Charges for Services Direct Cost (i)	Total Charges for Services Indirect Cost (j)	Total Charges for Services Total Cost (k)
1	403-403.1	Depreciation Expense			
2	404-405	Amortization Expense			
3	407.3-407.4	Regulatory Debits/Credits – Net			
4	408.1-408.2	Taxes Other Than Income Taxes	7,184,783	9,511,367	16,696,150
5	409.1-409.3	Income Taxes	(4,626,284)		(4,626,284)
6	410.1-411.2	Provision for Deferred Taxes	6,190,565		6,190,565
7	411.1-411.2	Provision for Deferred Taxes – Credit			
8	411.6	Gain from Disposition of Service Company Plant			
9	411.7	Losses from Disposition of Service Company Plant			
10	411.4-411.5	Investment Tax Credit Adjustment			
11	411.10	Accretion Expense			
12	412	Costs and Expenses of Construction or Other Services	475,293,658		475,293,658
13	416	Costs and Expenses of Merchandising, Jobbing, and Contract Work for Associated Companies			
14	418	Non-operating Rental Income			
15	418.1	Equity in Earnings of Subsidiary Companies			
16	419	Interest and Dividend Income	55,448	697	56,145
17	419.1	Allowance for Other Funds Used During Construction			
18	421	Miscellaneous Income or Loss		(34,394)	(34,394)
19	421.1	Gain on Disposition of Property			
20	421.2	Loss on Disposition Of Property			
21	425	Miscellaneous Amortization			
22	426.1	Donations	286,384	8,006,786	8,293,170
23	426.2	Life Insurance		(307,031)	(307,031)
24	426.3	Penalties	14,270	6,554	20,824
25	426.4	Expenditures for Certain Civic, Political and Related Activities	441,891	3,019,224	3,461,115
26	426.5	Other Deductions	202,316	3,270,056	3,472,372
27	427	Interest On Long-Term Debt			
28	428	Amortization of Debt Discount and Expense			
29	429	Amortization of Premium on Debt – Credit			
30	430	Interest on Debt to Associate Companies	435,844		435,844
31	431	Other Interest Expense		684	684
32	432	Allowance for Borrowed Funds Used During Construction			
33	500-509	Total Steam Power Generation Operation Expenses	21,549,899	5,099,811	26,649,710
34	510-515	Total Steam Power Generation Maintenance Expenses	12,512,724	165,687	12,678,411

Name of Respondent Xcel Energy Services Inc.		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, <u>2014</u>
Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies (continued)					
Line No.	Account Number (a)	Title of Account (b)	Total Charges for Services Direct Cost (i)	Total Charges for Services Indirect Cost (j)	Total Charges for Services Total Cost (k)
35	517-525	Total Nuclear Power Generation Operation Expenses	5,364,432		5,364,432
36	528-532	Total Nuclear Power Generation Maintenance Expenses	16,465		16,465
37	535-540.1	Total Hydraulic Power Generation Operation Expenses	501,451	200,769	702,220
38	541-545.1	Total Hydraulic Power Generation Maintenance Expenses	111,520	6,639	118,159
39	546-550.1	Total Other Power Generation Operation Expenses	1,705,597	866,379	2,571,976
40	551-554.1	Total Other Power Generation Maintenance Expenses	576,218	48,386	624,604
41	555-557	Total Other Power Supply Operation Expenses	9,238,454	1,668,633	10,907,087
42	560	Operation Supervision and Engineering	8,188,024	7,133,422	15,321,446
43	561.1	Load Dispatch-Reliability	55,937		55,937
44	561.2	Load Dispatch-Monitor and Operate Transmission System	4,661,786	4,220,975	8,882,761
45	561.3	Load Dispatch-Transmission Service and Scheduling	48,570		48,570
46	561.4	Scheduling, System Control and Dispatch Services			
47	561.5	Reliability Planning and Standards Development	315,574	74,260	389,834
48	561.6	Transmission Service Studies	32,974		32,974
49	561.7	Generation Interconnection Studies	112,495		112,495
50	561.8	Reliability Planning and Standards Development Services	4,438		4,438
51	562	Station Expenses (Major Only)	1,125,333		1,125,333
52	563	Overhead Line Expenses (Major Only)	1,367,611		1,367,611
53	564	Underground Line Expenses (Major Only)			
54	565	Transmission of Electricity by Others (Major Only)	22		22
55	566	Miscellaneous Transmission Expenses (Major Only)	7,685,882	598,272	8,284,154
56	567	Rents	1,370,541		1,370,541
57	567.1	Operation Supplies and Expenses (Nonmajor Only)			
58		Total Transmission Operation Expenses	24,969,187	12,026,929	36,996,116
59	568	Maintenance Supervision and Engineering (Major Only)	7,709		7,709
60	569	Maintenance of Structures (Major Only)			
61	569.1	Maintenance of Computer Hardware			
62	569.2	Maintenance of Computer Software			
63	569.3	Maintenance of Communication Equipment			
64	569.4	Maintenance of Miscellaneous Regional Transmission Plant			
65	570	Maintenance of Station Equipment (Major Only)	63,988		63,988
66	571	Maintenance of Overhead Lines (Major Only)	322,144		322,144
67	572	Maintenance of Underground Lines (Major Only)			
68	573	Maintenance of Miscellaneous Transmission Plant (Major Only)	144,480		144,480

Name of Respondent Xcel Energy Services Inc.		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, <u>2014</u>
Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies (continued)					
Line No.	Account Number (a)	Title of Account (b)	Total Charges for Services Direct Cost (i)	Total Charges for Services Indirect Cost (j)	Total Charges for Services Total Cost (k)
69	574	Maintenance of Transmission Plant (Nonmajor Only)			
70		Total Transmission Maintenance Expenses	538,321		538,321
71	575.1-575.8	Total Regional Market Operation Expenses	833,589		833,589
72	576.1-576.5	Total Regional Market Maintenance Expenses			
73	580-589	Total Distribution Operation Expenses	12,060,973	7,476,040	19,537,013
74	590-598	Total Distribution Maintenance Expenses	1,469,590		1,469,590
75		Total Electric Operation and Maintenance Expenses	576,816,399	51,100,610	627,917,009
76	700-798	Production Expenses (Provide selected accounts in a footnote)	191,241		191,241
77	800-813	Total Other Gas Supply Operation Expenses	734,439		734,439
78	814-826	Total Underground Storage Operation Expenses	5,151		5,151
79	830-837	Total Underground Storage Maintenance Expenses			
80	840-842.3	Total Other Storage Operation Expenses	17,808		17,808
81	843.1-843.9	Total Other Storage Maintenance Expenses	379		379
82	844.1-846.2	Total Liquefied Natural Gas Terminaling and Processing Operation Expenses			
83	847.1-847.8	Total Liquefied Natural Gas Terminaling and Processing Maintenance Expenses			
84	850	Operation Supervision and Engineering	669,314	279,531	948,845
85	851	System Control and Load Dispatching.	13,975	1,106,214	1,120,189
86	852	Communication System Expenses			
87	853	Compressor Station Labor and Expenses	7,855		7,855
88	854	Gas for Compressor Station Fuel			
89	855	Other Fuel and Power for Compressor Stations			
90	856	Mains Expenses	23,280		23,280
91	857	Measuring and Regulating Station Expenses	198		198
92	858	Transmission and Compression of Gas By Others			
93	859	Other Expenses	44,617	1,466	46,083
94	860	Rents	101,330		101,330
95		Total Gas Transmission Operation Expenses	860,569	1,387,211	2,247,780
96	861	Maintenance Supervision and Engineering			
97	862	Maintenance of Structures and Improvements			
98	863	Maintenance of Mains	102,567		102,567
99	864	Maintenance of Compressor Station Equipment	85		85
100	865	Maintenance of Measuring And Regulating Station Equipment	271,055		271,055
101	866	Maintenance of Communication Equipment	4,579	11,315	15,894
102	867	Maintenance of Other Equipment			
103		Total Gas Transmission Maintenance Expenses	378,286	11,315	389,601
104	870-881	Total Distribution Operation Expenses	4,697,922	9,014,646	13,712,568

Name of Respondent Xcel Energy Services Inc.			This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, <u>2014</u>
Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies (continued)						
Line No.	Account Number (a)	Title of Account (b)	Total Charges for Services Direct Cost (i)	Total Charges for Services Indirect Cost (j)	Total Charges for Services Total Cost (k)	
105	885-894	Total Distribution Maintenance Expenses	349,741		349,741	
106		Total Natural Gas Operation and Maintenance Expenses	7,235,536	10,413,172	17,648,708	
107	901	Supervision	17,684	500,961	518,645	
108	902	Meter reading expenses	88,180	3,931,369	4,019,549	
109	903	Customer records and collection expenses	382,497	56,417,900	56,800,397	
110	904	Uncollectible accounts				
111	905	Miscellaneous customer accounts expenses	38		38	
112	906	Total Customer Accounts Operation Expenses	488,399	60,850,230	61,338,629	
113	907	Supervision				
114	908	Customer assistance expenses	3,593,008	477,521	4,070,529	
115	909	Informational And Instructional Advertising Expenses	235,842	1,128,067	1,363,909	
116	910	Miscellaneous Customer Service And Informational Expenses				
117		Total Service and Informational Operation Accounts	3,828,850	1,605,588	5,434,438	
118	911	Supervision				
119	912	Demonstrating and Selling Expenses	24,431		24,431	
120	913	Advertising Expenses				
121	916	Miscellaneous Sales Expenses				
122		Total Sales Operation Expenses	24,431		24,431	
123	920	Administrative and General Salaries	38,609,195	98,950,485	137,559,680	
124	921	Office Supplies and Expenses	13,610,364	91,571,492	105,181,856	
125	923	Outside Services Employed	13,288,465	26,545,884	39,834,349	
126	924	Property Insurance		64,589	64,589	
127	925	Injuries and Damages	211,842	15,901,527	16,113,369	
128	926	Employee Pensions and Benefits	27,669,669	36,165,306	63,834,975	
129	928	Regulatory Commission Expenses	174,695		174,695	
130	930.1	General Advertising Expenses	2,523,935	8,327,366	10,851,301	
131	930.2	Miscellaneous General Expenses	979,399	6,925,885	7,905,284	
132	931	Rents	21,254,715	43,969,017	65,223,732	
133		Total Administrative and General Operation Expenses	118,322,279	328,421,551	446,743,830	
134	935	Maintenance of Structures and Equipment	131,545	2,866,766	2,998,311	
135		Total Administrative and General Maintenance Expenses	122,795,504	393,744,135	516,539,639	
136		Total Cost of Service	706,847,439	455,257,917	1,162,105,356	

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Xcel Energy Services Inc.			
FOOTNOTE DATA			

Schedule Page: 307 Line No.: 6 Column: e**Xcel Energy Joint Ventures:**

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

CapX2020 Joint Venture	\$2,173,817
Hayden Joint Venture	1,806,738
Comanche 3 Joint Venture	<u>358,976</u>
	<u>\$4,339,531</u>

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Name of Respondent Xcel Energy Services Inc.		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, <u>2014</u>
Schedule XIX - Miscellaneous General Expenses - Account 930.2					
1. Provide a listing of the amount included in Account 930.2, "Miscellaneous General Expenses" classifying such expenses according to their nature. Amounts less than \$50,000 may be grouped showing the number of items and the total for the group. 2. Payments and expenses permitted by Section 321 (b)(2) of the Federal Election Campaign Act, as amended by Public Law 94-283 in 1976 (2 U.S.C. 441(b)(2)) shall be separately classified.					
Line No.	Title of Account (a)	Amount (b)			
1	Utility Association Dues	3,948,323			
2	Board of Directors Fees and Expenses	2,788,673			
3	Shareholder Relation Expenses	958,906			
4	SEC Filing and Shareholder Reporting Expenses	208,643			
5	Other	739			
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40	Total	7,905,284			

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Xcel Energy Services Inc.			
Schedule XX - Organization Chart			

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

Organization Chart

Chief Executive Officer (CEO)
 Corporate Other
 Corporate Services
 Safety & Business Services
 Aviation & Travel Services
 Enterprise Security
 Property Services
 Safety, Workforce Relations & Training
 Business Systems
 Chief Administrative Officer (CAO)
 Enterprise Transformation Officer
 Resource Planning
 Corporate Secretary
 Corporate Compliance
 Knowledge Base
 Shareholder Relations
 Strategy Performance & Asset Management
 Customer Care
 Human Resources
 Payroll
 Marketing & Communications

 External Affairs
 Corporate & State External Affairs
 Federal Affairs
 Political/Grass Roots
 Financial Operations
 Audit Services
 Chief Financial Officer
 Controller
 Financial Planning & Analysis
 Investor Relations
 Revenue Requirements
 Risk Management
 Tax Services
 Treasurer

Service Function *

Executive Management
 Accounting, Financial Reporting & Taxes
 Executive Management
 Executive Management
 Aviation Services
 Executive Management & Facilities & Real Estate
 Facilities Admin. Services & Facilities & Real Estate
 Energy Supply Business Resources & Human Resources
 Business Systems
 Executive Management
 Information Technology
 Energy Markets Regulated Trading & Marketing
 Executive Management
 Executive Management
 Corporate Communications
 Investor Relations
 Corporate Communications
 Customer Service; Receipts Processing
 Human Resources
 Payroll
 Corporate Communications, Employee Communications &
 Marketing & Sales
 Corporate Communications & Government Affairs
 Corporate Communications & Government Affairs
 Government Affairs
 Government Affairs
 Accounting, Financial Reporting & Taxes
 Internal Audit
 Accounting, Financial Reporting & Taxes
 Accounting, Financial Reporting & Taxes
 Accounting, Financial Reporting & Taxes
 Investor Relations
 Rates & Regulation
 Finance & Treasury
 Accounting, Financial Reporting & Taxes
 Finance & Treasury

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Xcel Energy Services Inc.			
Schedule XX - Organization Chart			

General Counsel	Legal
Claims	Claims Services
Corporate Policy & Strategy	Government Affairs; Rates & Regulation
	Corporate Strategy & Business Development & Business Systems
Legal Services	Legal
Operations Services	Executive Management
Distribution Operations	Construction O&M; Energy Delivery Marketing; Engineering/Design
Gas Systems	Engineering/Design; Construction O&M; Executive Management
Energy Supply	Energy Supply Business Resources
Engineering & Construction	Energy Supply Engineering & Environmental; Energy Supply Business Resources
Environmental	Energy Supply Engineering & Environmental
Operations (Regional Generation)	Energy Supply Business Resources
Technical Services	Energy Supply Business Resources
Commercial Operations	Energy Markets Regulated Trading & Marketing & Energy Markets – Fuel Procurement
Supply Chain	Supply Chain; Supply Chain Special Programs; Payment & Reporting & Fleet
Transmission	Engineering/Design; Construction O&M; Engineering/Design-Electric Transmission/Substations
Group President	Executive Management
NSPM President	Rates & Regulation
NSPW President	Government Affairs & Rates & Regulation
PSCo President	Government Affairs & Rates & Regulation
SPS President	Government Affairs & Rates & Regulation

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

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Xcel Energy Services Inc.			
Schedule XXI - Methods of Allocation			

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

2. Include any other allocation methods used to allocate costs.

Service Department or Function	Basis of Allocation*
Executive Management Services	Executive Management indirect costs are allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.
Investor Relations	Investor Relations indirect costs are allocated based on a three-factor formula that is comprised of the average of the Revenue ratio, the Employee Ratio and the Total Assets Ratio.
Internal Audit	Internal Audit indirect costs are allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.
Legal	Legal indirect costs are allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.
Claims Services	Claims Services costs are direct charged.
Corporate Communications	Corporate Communications indirect costs are allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.
Employee Communications	Employee Communications indirect costs are allocated based on the Employee Ratio.
Corporate Strategy & Business Development	Corporate Strategy & Business Development indirect costs are allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.
Government Affairs	Government Affairs indirect costs are allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.
Facilities & Real Estate	Facilities & Real Estate indirect costs are allocated to the Operating Companies based on the Employee Ratio.
Facilities Administrative Services	Facilities Administrative Services indirect costs are allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.
Supply Chain	Supply Chain is direct charged and administrative support

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Xcel Energy Services Inc.			
Schedule XXI - Methods of Allocation			

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

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Schedule XXI - Methods of Allocation			

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

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Schedule XXI - Methods of Allocation			

	Revenue Ratio, the Employee Ratio and the Total Assets Ratio.
Fleet	Fleet is 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. Additionally, the "Basis for Allocation" column sets forth the primary allocation methods for service function; however, others may be used based on a case-by-case basis depending on the specific work being performed.

Allocation Ratios

The following ratios will be utilized as outlined above.

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

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

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

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

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

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

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

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

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

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Schedule XXI - Methods of Allocation			

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

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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.

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;

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- (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

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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;

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(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.

Compass/Maximo

Workorder Number	Allocation Method	Reasonableness of Allocation Method	2016Test Year Percentages		
			FERC 506	FERC 539	FERC 549
12001	Maximo System users	Number of Maximo Users is used to allocate IT costs for the Compass/Maximo software since it has a direct causal relationship with the operations supported by Maximo (i.e. Hydro, Steam Electric, Chiller, A&G).	83.1008%	0.3101%	16.5891%

- * FERC 506 - Miscellaneous steam power expenses
- * FERC 539 - Miscellaneous hydraulic power generation expenses
- * FERC 549 - Miscellaneous other power generation expenses

Electric Management System (EMS, also known as Electric SCADA)

Workorder Number	Allocation Method	Reasonableness of Allocation Method	2016Test Year Percentages		
			FERC 556	FERC 561	FERC 581
12004	Number of Remote Terminal Units (RTUs)	Number of RTUs is a reasonable methodology because the RTUs transmit the data used by the SCADA system.	3.2680%	61.6441%	35.0879%

- * FERC 556 - System Control and Load Dispatching (Production)
- * FERC 561 - Load Dispatching (Transmission)
- * FERC 581 - Load Dispatching (Distribution)

Gas SCADA

Workorder Number	Allocation Method	Reasonableness of Allocation Method	2016Test Year Percentages		
			FERC 851	FERC 871	
12008	Gas Transmission & Distribution Plant	Gas transmission and distribution plant is a reasonable methodology because this system is used to communicate between the control rooms at the plants, transmission and distribution areas.	7.3683%	92.6317%	

* FERC 851 - System Control and Load Dispatching (Gas Transmission)

* FERC 871 - Distribution Load Dispatching (Gas Distribution)

Network Services

Workorder Number	Allocation Method	Reasonableness of Allocation Method	2016Test Year Percentages		
			FERC 588	FERC 880	
12011	Distribution Plant	Distribution plant is a reasonable methodology because these locations primarily benefit electric and gas distribution	78.8328%	21.1672%	

* FERC 588 - Miscellaneous Distribution Expenses (Electric Distribution)

* FERC 880 - Other Expenses (Gas Distribution)

Cost Categories	Allocation Method	Reasonableness of Allocation Method	2016 Test Year Percentages	
			Electric	Gas
FERC Accounts 901-917 (excluding commodity bad debt in FERC 904)	Customer bill counts for the electric and gas departments.	Using Customer bill counts is reasonable because costs recorded in FERC accounts 901-917 are customer related.	79.9724%	20.0276%
FERC 904 (commodity bad debt portion)	Average total electric and gas revenues for the previous four years	Using a revenue allocator is reasonable because commodity bad debt costs have a cost-causative relationship with uncollectible utility revenues.	84.5826%	15.4174%
FERC Accounts 920-924	3-factor allocation for the electric and gas departments.	Using a 3-factor allocation is reasonable because costs recorded in FERC accounts 920-924 are general in nature.	92.2367%	7.7633%
FERC Accounts 925-926	Operating labor for the electric and gas departments.	Using Operating labor is reasonable because costs recorded in FERC accounts 925-926 are employee related.	92.9619%	7.0381%
FERC Accounts 927-935	3-factor for the electric and gas departments.	Using a 3-factor allocation is reasonable because costs recorded in FERC accounts 927-937 are general in nature.	92.2367%	7.7633%

**Administrative Services Agreements Charges
between Regulated Utility Operating Companies and NSPM
2016 Budget**

	Budget Year 2016	Total by Operating Co	Total for SPS and PSCo
<u>NSPM charges to NSPW</u>			
Hazardeous Waste Consolidation Facility	\$ 137,960		
Supplemental craft worker support for plant maintenance	\$ 68,841		
Facilities Overheads	\$ 4,575		
Labor Additives	\$ 29,586		
Transmission Fleet and Other Services	<u>\$ 5,353</u>		
Total Charges to NSPW		\$ 246,315	
<u>NSPW charges to NSPM</u>			
Facilities Overheads	\$ 6,962		
Siting & Land Rights	\$ 3,604		
Transmission Support	\$ 2,580		
Total Charges to NSPM		<u>\$ 13,146</u>	
		<u>\$ 259,461</u>	
<u>NSPM charges to PSCo</u>			
Facilities Overheads	\$ 10,869		
Labor Additives	<u>\$ 24,756</u>		
Total Charges to PSCo		\$ 35,625	
<u>PSCo charges to NSPM</u>			
Facilities Overheads	\$ 4,063		
Siting & Land Rights	<u>\$ 42</u>		
		<u>\$ 4,105</u>	\$ 39,730
<u>NSPM charges to SPS</u>			
Facilities Overheads	\$ 762		
Labor Additives	<u>\$ 192</u>		
Total Charges to SPS		\$ 954	
<u>SPS Charges to NSPM</u>			
Facilities Overheads	<u>\$ 85</u>		
Total Charges to NSPM		<u>\$ 85</u>	\$ 1,038
Charges from/to Regulated Utility Operating Companies other than NSPW			<u>\$ 40,768</u>

Definitions:

NSPM - Northern States Power Company-Minnesota

NSPW - Northern States Power Company-Wisconsin

PSCo - Public Service Company of Colorado

SPS - Southwestern Public Service

Minnesota
Nonregulated Business Activity Significance
Fiscal Year Ended 12/31/2014

	<u>Consolidated Total NSPM</u>		<u>All Other Nonreg</u>		<u>% of Total</u>
Total Revenues	\$ 4,988,525	(1)	\$ 28,473	(1)	0.57%
Less: Interest charges and financing cost	(188,956)	(1)	(178)	(1)	
Income tax expense	(198,090)	(1)	7,004	(1)	
Income from continuing operations	(404,915)	(1)	(13,460)	(1)	
Subtotal	\$ 4,196,564		\$ 21,839		
Add: Other income, net of nonoperating expenses	580	(2)	0		
Allowance for funds used during construction - equity	23,788	(2)	0		
Total Operating Expenses	\$ 4,220,932	(3)	\$ 21,839	(4)	
Less: Purchased COGS	(2,226,320)	(3)	(17,371)	(3)	
Operating Expense, Net of Purchased COGS	\$ 1,994,612	(3)	\$ 4,468	(4)	0.22%

Calculation of Purchased Fuel, Power & Gas Expense (Purchased COGS)

Elect Fuel and Purch Power	\$ 1,676,474	(2)		
Purchased Gas Expense	532,475	(2)		
Cost of sales - nonregulated and other	17,371	(2)	\$ 17,371	(2)
Total Purchased COGS	\$ 2,226,320	(3)	\$ 17,371	

Calculation of Operating Expenses excluding Purchased COGS

O&M expenses	\$ 1,223,829	(2)		
Conservation program expenses	138,105	(2)		
Depreciation and amortization	410,840	(2)		
Taxes - other than income tax	221,838	(2)		
Operating Expense Net of Purchased COGS	\$ 1,994,612	(3)		

Total Operating Expenses (excluding interest and income tax expenses)	<u>\$ 4,220,932</u>	(2)		

(1) From page 95 of Northern States Power Company's (NSPM) Form 10-K filed with the SEC for the fiscal year ended December 31, 2014. According to NSPM, the "All Other" column primarily includes appliance repair services, nonutility real estate activities, and revenues associated with processing solid waste into refuse-derived fuel.

(2) From page 41 of Northern States Power Company's (NSPM) Form 10-K filed with the SEC for the fiscal year ended December 31, 2014.

(3) Calculated with numbers from page 36 of NSPM's 12/31/2014 Form 10-K, as shown.

(4) Calculated number from above.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2014

or

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number 001-31387

NORTHERN STATES POWER COMPANY

(Exact name of registrant as specified in its charter)

Minnesota**41-1967505**

(State or other jurisdiction of incorporation or organization)

(I.R.S. Employer Identification No.)

414 Nicollet Mall, Minneapolis, Minnesota 55401

(Address of principal executive offices)

Registrant's telephone number, including area code: **612-330-5500**Securities registered pursuant to Section 12(b) of the Act: **None**Securities registered pursuant to section 12(g) of the Act: **None**Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. ☒ Yes ☐ NoIndicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. ☐ Yes ☒ NoIndicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☒ Yes ☐ NoIndicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 and Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ☒ Yes ☐ NoIndicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulations S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐Accelerated filer ☐Non-accelerated filer ☒Smaller Reporting Company ☐

(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). ☐ Yes ☒ No

As of Feb. 20, 2015, 1,000,000 shares of common stock, par value \$0.01 per share, were outstanding, all of which were held by Xcel Energy Inc., a Minnesota corporation.

DOCUMENTS INCORPORATED BY REFERENCE

Xcel Energy Inc.'s Definitive Proxy Statement for its 2015 Annual Meeting of Shareholders is incorporated by reference into Part III of this Form 10-K.

Northern States Power Company meets the conditions set forth in General Instructions I(1)(a) and (b) of Form 10-K and is therefore filing this form with the reduced disclosure format permitted by General Instruction I(2).

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This Form 10-K is filed by NSP-Minnesota. NSP-Minnesota is a wholly owned subsidiary of Xcel Energy Inc. Additional information on Xcel Energy is available in various filings with the SEC. This report should be read in its entirety.

PART I

Item 1 — Business

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

Xcel Energy Inc.'s Subsidiaries and Affiliates (current and former)

NMC	Nuclear Management Company, LLC
NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP System	The electric production and transmission system of NSP-Minnesota and NSP-Wisconsin operated on an integrated basis and managed by NSP-Minnesota
NSP-Wisconsin	Northern States Power Company, a Wisconsin corporation
PSCo	Public Service Company of Colorado
SPS	Southwestern Public Service Company
Utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
Xcel Energy	Xcel Energy Inc. and its subsidiaries

Federal and State Regulatory Agencies

ASLB	Atomic Safety and Licensing Board
CFTC	Commodity Futures Trading Commission
D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
DOC	Minnesota Department of Commerce
DOE	United States Department of Energy
DOI	United States Department of the Interior
DOT	United States Department of Transportation
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
MPCA	Minnesota Pollution Control Agency
MPSC	Michigan Public Service Commission
MPUC	Minnesota Public Utilities Commission
NDPSC	North Dakota Public Service Commission
NERC	North American Electric Reliability Corporation
NRC	Nuclear Regulatory Commission
PSCW	Public Service Commission of Wisconsin
SDPUC	South Dakota Public Utilities Commission
SEC	Securities and Exchange Commission

Electric, Purchased Gas and Resource Adjustment Clauses

CIP	Conservation improvement program
EIR	Environmental improvement rider
EPU	Extended power uprate
FCA	Fuel clause adjustment
PGA	Purchased gas adjustment
RDF	Renewable development fund
RES	Renewable energy standard
SEP	State energy policy
TCR	Transmission cost recovery adjustment

<i>Other Terms and Abbreviations</i>	
AFUDC	Allowance for funds used during construction
ALJ	Administrative law judge
APBO	Accumulated postretirement benefit obligation
ARO	Asset retirement obligation
ASU	FASB Accounting Standards Update
BART	Best available retrofit technology
C&I	Commercial and Industrial
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CapX2020	Alliance of electric cooperatives, municipalities and investor-owned utilities in the upper Midwest involved in a joint transmission line planning and construction effort
CO ₂	Carbon dioxide
CON	Certificate of need
CPCN	Certificate of public convenience and necessity
CSAPR	Cross-State Air Pollution Rule
CWIP	Construction work in progress
EGU	Electric generating unit
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
FTR	Financial transmission right
FTY	Forecast test year
GAAP	Generally accepted accounting principles
GHG	Greenhouse gas
JOA	Joint operating agreement
LCM	Life cycle management
LLW	Low-level radioactive waste
LNG	Liquefied natural gas
MGP	Manufactured gas plant
MISO	Midcontinent Independent System Operator, Inc.
Moody's	Moody's Investor Services
MVP	Multi-value project
Native load	Customer demand of retail and wholesale customers that a utility has an obligation to serve under statute or long-term contract.
NEI	Nuclear Energy Institute
NOL	Net operating loss
NOV	Notice of violation
NO _x	Nitrogen oxide
NSPS	New source performance standard
NYISO	New York Independent System Operator
O&M	Operating and maintenance
OCI	Other comprehensive income
PCB	Polychlorinated biphenyl
PFS	Private Fuel Storage, LLC
PI	Prairie Island nuclear generating plant
PJM	PJM Interconnection, LLC
PM	Particulate matter
PPA	Purchased power agreement
PRP	Potentially responsible party
PTC	Production tax credit
PV	Photovoltaic
REC	Renewable energy credit

ROE	Return on equity
ROFR	Right of first refusal
RPS	Renewable portfolio standard
RSG	Revenue sufficiency guarantee
RTO	Regional Transmission Organization
SCR	Selective catalytic reduction
SIP	State implementation plan
SO ₂	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
Standard & Poor's	Standard & Poor's Ratings Services

Measurements

Bcf	Billion cubic feet
KV	Kilovolts
KWh	Kilowatt hours
MMBtu	Million British thermal units
MW	Megawatts
MWh	Megawatt hours

COMPANY OVERVIEW

NSP-Minnesota was incorporated in 2000 under the laws of Minnesota. NSP-Minnesota is a utility primarily engaged in the generation, purchase, transmission, distribution and sale of electricity in Minnesota, North Dakota and South Dakota. The wholesale customers served by NSP-Minnesota comprised approximately seven percent of its total KWh sold in 2014. NSP-Minnesota also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas in Minnesota and North Dakota. NSP-Minnesota provides electric utility service to approximately 1.4 million customers and natural gas utility service to approximately 0.5 million customers. Approximately 88 percent of NSP-Minnesota's retail electric operating revenues were derived from operations in Minnesota during 2014. Although NSP-Minnesota's large commercial and industrial electric retail customers are comprised of many diversified industries, a significant portion of NSP-Minnesota's large commercial and industrial electric sales include the following industries: petroleum, coal and food products. For small commercial and industrial customers, significant electric retail sales include the following industries: real estate and educational services. Generally, NSP-Minnesota's earnings contribute approximately 35 percent to 45 percent of Xcel Energy's consolidated net income.

The electric production and transmission costs of the entire NSP System are shared by NSP-Minnesota and NSP-Wisconsin. A FERC-approved Interchange Agreement between the two companies provides for the sharing of all generation and transmission costs of the NSP System. Generally, sales to NSP-Wisconsin through the Interchange Agreement account for approximately 10 percent of NSP-Minnesota's consolidated revenues.

NSP-Minnesota owns the following direct subsidiaries: United Power and Land Company, which holds real estate; and NSP Nuclear Corporation, which owns NMC, an inactive company.

NSP-Minnesota conducts its utility business in the following reportable segments: regulated electric utility, regulated natural gas utility and all other. See Note 15 to the consolidated financial statements for further discussion relating to comparative segment revenues, net income and related financial information.

NSP-Minnesota's corporate strategy focuses on four core objectives: improving utility performance; driving operational excellence; providing options and solutions to customers; and investing for the future.

ELECTRIC UTILITY OPERATIONS

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — Retail rates, services and other aspects of NSP-Minnesota's operations are regulated by the MPUC, the NDPSC and the SDPUC within their respective states. The MPUC also has regulatory authority over security issuances, property transfers, mergers, dispositions of assets and transactions between NSP-Minnesota and its affiliates. In addition, the MPUC reviews and approves NSP-Minnesota's electric resource plans for meeting customers' future energy needs. The MPUC also certifies the need and siting for generating plants greater than 50 MW and transmission lines greater than 100 KV that will be located within the state. No large power plant or transmission line may be constructed in Minnesota except on a site or route designated by the MPUC. The NDPSC and SDPUC have regulatory authority over generation and transmission facilities, along with the siting and routing of new generation and transmission facilities in North Dakota and South Dakota, respectively.

NSP-Minnesota is subject to the jurisdiction of the FERC with respect to its wholesale electric operations, hydroelectric licensing, accounting practices, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transfers and mergers, and natural gas transactions in interstate commerce. NSP-Minnesota has been granted continued authorization from the FERC to make wholesale electric sales at market-based prices. NSP-Minnesota is a transmission owning member of the MISO RTO.

Fuel, Purchased Energy and Conservation Cost-Recovery Mechanisms — NSP-Minnesota has several retail adjustment clauses that recover fuel, purchased energy and other resource costs:

- *CIP* — The CIP recovers the costs of conservation and demand-side management programs that help customers save energy.
- *EIR* — The EIR recovers the costs of environmental improvement projects.
- *RDF* — The RDF allocates money collected from retail customers to support the research and development of emerging renewable energy projects and technologies.
- *RES* — The RES recovers the cost of new renewable generation.
- *SEP* — The SEP recovers costs related to various energy policies approved by the Minnesota legislature.

- *TCR* — The TCR recovers costs associated with new investments in electric transmission.
- *Infrastructure* — The Infrastructure rider recovers costs associated with specific investments in generation and incremental property taxes.

NSP-Minnesota's retail electric rates in Minnesota, North Dakota and South Dakota include a FCA for monthly billing adjustments for changes in prudently incurred costs of fuel, fuel related items and purchased energy. NSP-Minnesota is permitted to recover these costs through FCA mechanisms approved by the regulators in each jurisdiction. In general, capacity costs are not recovered through the FCA. In addition, costs associated with MISO are generally recovered through either the FCA or base rates.

Minnesota state law requires NSP-Minnesota to invest two percent of its state electric revenues in CIP. NSP-Minnesota was in compliance with this standard in 2014 and expects to be in compliance in 2015. These costs are recovered through an annual cost-recovery mechanism for electric conservation and energy management program expenditures.

CIP Triennial Plan — In 2012, the DOC approved NSP-Minnesota's 2013 through 2015 CIP Triennial Plan, which increases the savings goals and budgets over the previous plan. The plan sets an electric goal of annually saving the equivalent of 1.5 percent of sales (calculated on a historical three-year average, excluding opt-out customers) and an annual natural gas goal of saving 1.0 percent of sales.

Capacity and Demand

Uninterrupted system peak demand for the NSP System's electric utility for each of the last three years and the forecast for 2015, assuming normal weather, is listed below.

	System Peak Demand (in MW)			
	2012	2013	2014	2015 Forecast
NSP System	9,475	9,524	8,848	9,301

The peak demand for the NSP System typically occurs in the summer. The 2014 uninterrupted system peak demand for the NSP System occurred on July 21, 2014. The 2014 system peak demand was lower due to cooler summer weather. The 2015 forecast assumes normal peak day weather.

Energy Sources and Related Transmission Initiatives

The NSP System expects to use existing power plants, power purchases, CIP options, new generation facilities and expansion of existing power plants to meet its system capacity requirements.

Purchased Power — NSP-Minnesota has contracts to purchase power from other utilities and independent power producers. Long-term purchased power contracts typically require a periodic payment to secure the capacity and a charge for the associated energy actually purchased. NSP-Minnesota also makes short-term purchases to meet system load and energy requirements, to replace generation from company-owned units under maintenance or during outages, to meet operating reserve obligations, or to obtain energy at a lower cost.

Purchased Transmission Services — In addition to using their integrated transmission system, NSP-Minnesota and NSP-Wisconsin have contracts with MISO and regional transmission service providers to deliver power and energy to the NSP System.

NSP-Minnesota's Filing in Support of e21 Initiative — In December 2014, a collaborative report was issued in Minnesota by a diverse stakeholder group known as the e21 Initiative. The e21 report released a set of recommendations that are intended to act as a blueprint for a new customer-centric, performance-based regulatory approach.

Following the e21 report, NSP-Minnesota filed with the MPUC a plan for supporting the e21 Initiative, which includes the following key objectives:

- Leading the effort to reduce carbon emissions 40 percent by 2030 from 2005 levels;
- Advancing distribution grid modernization;
- Providing our customers with a platform of innovative services and product offerings; and

- Implementing a new regulatory framework that provides both predictable rates for customers and a more timely and nimble review while retaining key benefits of the existing process, thus freeing time for regulatory agencies, stakeholders and utilities to focus on achieving policy objectives.

NSP-Minnesota plans to work with the MPUC and various stakeholders during 2015 to continue the dialogue and implementation of the e21 Initiative and proposals presented by NSP-Minnesota.

NSP System Resource Plans — In January 2015, NSP-Minnesota filed its 2016-2030 Resource Plan with the MPUC, proposing to achieve a 40 percent reduction in carbon emissions by 2030 from 2005 levels through the significant addition of renewables, continued commitment to specific CIP annual achievements, and the continued operation of its existing cost-effective thermal generation. The plan positions NSP-Minnesota to be responsive to future environmental requirements and market trends, builds on the significant investments already made in the NSP System, and acknowledges the divergence in state energy policies within the NSP System. Key points of the resource plan include:

- Adding 600 MW of wind by 2020 and 1,200 MW by 2027, bringing total wind power on the NSP System to over 3,600 MW;
- Adding 187 MW of large-scale solar energy by 2016 and an additional 1,700 MW of large-scale solar and 500 MW of customer-driven small-scale solar; bringing total solar power on the NSP System to approximately 2,400 MW;
- Operating the Monticello and PI nuclear plants through their current licenses; and
- Continuing to run Sherco Units 1 and 2 with gradually decreasing reliance through 2030.

In February 2015, the MPUC approved the Competitive Acquisition Plan (CAP), in which NSP-Minnesota is required to add capacity to its system to meet a resource need as follows:

- Enter into an agreement for 100 MW of distributed solar with Geronimo Energy LLC;
- Enter into an agreement with Calpine Corporation for a 345 MW expansion at its Mankato Energy Center; and
- Construct a 215 MW Black Dog Unit 6 combustion turbine.

NSP-Minnesota also proposed use of a collaborative stakeholder process to guide its five-year action plan, and to facilitate the necessary update of its resource analysis to incorporate the CAP outcomes and significantly higher than expected response to its Community Solar Gardens program.

CapX2020 — The estimated cost of the five major CapX2020 transmission projects listed below is \$2.0 billion. NSP-Minnesota and NSP-Wisconsin are responsible for approximately \$1.1 billion of the total investment.

Hampton, Minn. to Rochester, Minn. to La Crosse, Wis. 345 KV transmission line

Construction on the project started in Minnesota in January 2013 and the project is expected to go into service in 2016, although segments are being placed in service as they are completed.

Monticello, Minn. to Fargo, N.D. 345 KV transmission line

In December 2011, the Monticello, Minn. to St. Cloud, Minn. portion of the Monticello, Minn. to Fargo, N.D. project was placed in service. In April 2014, the St. Cloud, Minn. to Alexandria, Minn. portion of the project was placed in service. In January 2013, construction started on the project in North Dakota. The final phase of the project, Alexandria, Minn. to Fargo, N.D. is expected to go into service in 2015.

Brookings County, S.D. to Hampton, Minn. 345 KV transmission line

In December 2011, MISO granted the final approval of the project as a MVP. Construction started on the project in Minnesota in May 2012. The project is expected to go fully into service in 2015, although segments are being placed in service as they are completed.

Bemidji, Minn. to Grand Rapids, Minn. 230 KV transmission line

The Bemidji, Minn. to Grand Rapids, Minn. line was placed in service in September 2012.

Big Stone South to Brookings County, S.D. 345 KV transmission line

In December 2011, MISO granted final approval of the project as a MVP. In March 2014, the SDPUC approved a permit for construction of the project's southern portion. Construction is anticipated to begin in late 2015, with completion in 2017.

Minnesota Solar — Minnesota legislation requires 1.5 percent of a public utility’s total electric retail sales to retail customers be generated using solar energy by 2020. Of the 1.5 percent, 10 percent must come from systems sized less than 20 kilowatts. There are two customer-facing solar programs authorized by the legislature: a community solar garden program that provides bill credits to participating subscribers, and a solar production incentive program for systems equal to or less than 20 kilowatts with authorized payments of \$5.0 million per year over five years. NSP-Minnesota launched its Solar*Rewards Community program in December 2014.

The legislation also provides for an alternative tariff based on a distributed solar value or Value of Solar (VOS) methodology. In March 2014, a VOS methodology was approved by the MPUC. However, in September 2014 the MPUC determined that the VOS is not in the public interest for use with community solar gardens. The MPUC instead approved a retail rate based credit ranging from 9.5 to 15 cents per kilowatt hour. The actual bill credit amount is dependent on customer class as well as customers’ willingness to transfer the RECs to NSP-Minnesota.

Annual Automatic Adjustment (AAA) of Charges — In June 2013, the DOC proposed that the MPUC adopt a fuel clause incentive that would normalize FCA recovery using monthly patterns derived from averages of the prior three-year period, setting and fixing this level during a rate case with no adjustment between rate cases. NSP-Minnesota and other utilities opposed this proposal. The DOC proposal is pending MPUC action.

Additionally, the DOC has indicated it will review prudence of replacement power costs associated with the Sherco Unit 3 outage event within the 2013 AAA docket. The 2013 and 2012 AAA dockets remain pending.

Minneapolis, Minn. Franchise Agreement — In October 2014, the City of Minneapolis and Xcel Energy signed a 10 year franchise agreement. The City of Minneapolis has the option to end the agreement any time after the first five years and the option to extend it to a maximum of 20 years if both parties agree. A separate clean energy partnership agreement with the City of Minneapolis was also signed, which establishes a board comprised of city and utility officials tasked with creating a work plan to promote energy efficiency, the use of renewable energy, and the reduction of carbon emissions.

Nuclear Power Operations and Waste Disposal

NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the PI plant. Nuclear power plant operations produce gaseous, liquid and solid radioactive wastes which are controlled by federal regulation. High-level radioactive wastes primarily include used nuclear fuel. LLW consists primarily of demineralizer resins, paper, protective clothing, rags, tools and equipment that have become contaminated through use in a plant.

NRC Regulation — The NRC regulates the nuclear operations of NSP-Minnesota. Decisions by the NRC can significantly impact the operations of the nuclear generating plants.

The NRC imposed new requirements after events at the nuclear generating plant in Fukushima, Japan. In 2012, the NRC issued orders which included requirements for mitigation strategies for beyond-design-basis external events, requirements with regard to reliable spent fuel instrumentation and requirements with regard to reliable hardened containment vents, which are applicable to boiling water reactor containments at the Monticello plant. The NRC also requested additional information including requirements to perform walkdowns of seismic and flood protection, to evaluate seismic and flood hazards and to assess the emergency preparedness staffing and communications capabilities at each plant. Based on current refueling outage plans, the dates of the required compliance are expected to begin in 2015 with all units expected to be fully compliant by December 2016.

In 2013, the NRC issued a revised order with regard to reliable hardened containment vents. Phase 1 addresses severe accident conditions under which the existing hardened vent which comes off of the wet portion of the containment needs to operate. Phase 2 addresses a second hardened vent off of the dry portion of the containment, or a containment venting strategy that makes it unlikely that a licensee would need to vent from the dry portion of the containment. Compliance with the revised order will be completed during refueling outages in 2017-2019.

NSP-Minnesota expects that complying with these external event requirements will cost approximately \$90 to \$100 million at the Monticello and PI plants. The majority of these costs are expected to be capital in nature. NSP-Minnesota believes the costs associated with compliance would be recoverable from customers through regulatory mechanisms and does not expect a material impact on its results of operations, financial position, or cash flows.

The NRC continues to review its requirements for mitigating the risks of external events on nuclear plants. In 2014, the NRC issued a draft of proposed regulatory guidance for risk mitigation of tornado missiles (projectiles impacting the plant). NSP-Minnesota expects the costs associated with compliance with new NRC regulatory guidance for missile protection to be capital in nature and recoverable from customers. NSP-Minnesota is still evaluating the proposed new requirements and has not yet estimated their financial impact.

Nuclear Regulatory Performance — Since 2000, the NRC has had in place a Reactor Oversight Process (ROP) that classifies U.S. nuclear reactors into various categories (referred to as Columns, from 1 to 5) based on the significance of issues identified in performance indicators or inspection findings. Such issues are evaluated as either green, white, yellow, or red based on their safety significance, with green representing the least safety concern and red representing the most concern. At Dec. 31, 2014, PI Units 1 and 2 were in Column 1 (Licensee Response) with all green performance indicators and no greater than green findings or violations. Monticello was in Column 3 (Degraded Cornerstone) with all green performance indicators and a yellow finding related to flood control. The NRC has completed their inspection that will allow the yellow finding to be closed out. The NRC has notified Monticello that it has a potentially greater than green finding related to plant security which was immediately remedied. Xcel Energy expects to be formally notified of the closeout of the yellow finding, a final determination of the significance of the security finding, and Monticello's overall column status under the NRC's ROP in the first half of 2015. Until the NRC makes its determination, we are unable to estimate the cost or impact of any responsive actions required.

LLW Disposal — LLW from NSP-Minnesota's Monticello and PI nuclear plants is currently disposed at the Clive facility located in Utah and Waste Control Specialists facility located in Texas. If off-site LLW disposal facilities become unavailable, NSP-Minnesota has storage capacity available on-site at PI and Monticello that would allow both plants to continue to operate until the end of their current licensed lives.

High-Level Radioactive Waste Disposal — The federal government has the responsibility to permanently dispose of domestic spent nuclear fuel and other high-level radioactive wastes. The Nuclear Waste Policy Act requires the DOE to implement a program for nuclear high-level waste management. This includes the siting, licensing, construction and operation of a repository for spent nuclear fuel from civilian nuclear power reactors and other high-level radioactive wastes at a permanent federal storage or disposal facility.

Nuclear Geologic Repository - Yucca Mountain Project

In 2002, the U.S. Congress designated Yucca Mountain, Nevada as the first deep geologic repository. In 2008, the DOE submitted an application to construct a deep geologic repository at this site to the NRC. In 2010, the DOE announced its intention to stop the Yucca Mountain project and requested the NRC approve the withdrawal of the application. In 2010, the ASLB issued a ruling that the DOE could not withdraw the Yucca Mountain application.

The DOE's decision and the resulting stoppage of the NRC's review has prompted multiple legal challenges, including the DOE's authority to stop the project and withdraw the application, the DOE's authority to continue to collect the nuclear waste fund fee and the NRC's authority to stop their review of the DOE's application.

In August 2013, the D.C. Court of Appeals ordered the NRC to complete their review of the DOE's application to construct the Yucca Mountain repository. In November 2013, the NRC complied by issuing an order to the NRC Staff to complete and publish a safety evaluation report on the proposed Yucca Mountain nuclear spent fuel and waste repository. The NRC also requested that the DOE prepare a supplemental environmental impact statement (EIS) so the NRC Staff can complete its review.

In November 2013, the U.S. Court of Appeals ordered the DOE to suspend the collection of the nuclear waste fund fee from nuclear utilities and to recommend to Congress that the nuclear waste fund fee be set to zero. In January 2014, the DOE sent its court mandated proposal to adjust the current fee to zero, which Congress approved in May 2014.

At the time that the DOE decided to stop the Yucca Mountain project and withdraw the application, the Secretary of Energy convened a Blue Ribbon Commission to recommend alternatives to Yucca Mountain for disposal of used nuclear fuel. In January 2012, the Blue Ribbon Commission report was issued. In January 2013, the DOE provided its report to Congress relative to their plans to implement the Blue Ribbon Commission's recommendations including the required legislative changes and authorizations. The report also announced the Obama Administration's intent to make a pilot consolidated interim storage facility available in 2021, a larger consolidated interim storage facility available in 2025 and a deep geologic repository available in 2048. See Note 12 and Note 13 to the consolidated financial statements for further discussion.

Nuclear Spent Fuel Storage

NSP-Minnesota has interim on-site storage for spent nuclear fuel at its Monticello and PI nuclear generating plants. As of Dec. 31, 2014, there were 38 casks loaded and stored at the PI plant and 15 canisters loaded and stored at the Monticello plant. An additional 26 casks for PI and 15 canisters for Monticello have been authorized by the State of Minnesota. This currently authorized storage capacity is sufficient to allow NSP-Minnesota to operate until the end of the operating licenses in 2030 for Monticello, 2033 for PI Unit 1, and 2034 for PI Unit 2. Authorizations for additional spent fuel storage capacity may be required at each site to support either continued operation or decommissioning if the federal government does not begin operation of a consolidated interim storage installation by the time frames established in the DOE's Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste issued in January 2013.

PFS — The eight partners of PFS, including NSP-Minnesota, have withdrawn their license termination request from the NRC and have stopped activities to dissolve the LLC. This action was taken when the NRC changed its fee rules to no longer require certain licensees like PFS to pay annual fees until their facility becomes operational. PFS is currently reviewing its plans for the future.

NRC Waste Confidence Decision (WCD) — In June 2012, the D.C. Circuit issued a ruling to vacate and remand the NRC's WCD. The WCD assesses how long temporary on-site storage can remain safe and when facilities for the disposal of nuclear waste will become available. The D.C. Circuit remanded the WCD to the NRC and directed it to prepare an EIS if there are significant impacts or an environmental assessment to support a finding of no significant impact. In September 2014, the NRC published a Generic Environmental Impact Statement (GEIS) and revised WCD rule, now called the Continued Storage Rule (CSR) on the temporary on-site storage of spent nuclear fuel. Issuance of the CSR now allows the NRC to proceed with final license decisions regarding the new and renewal of plant and Independent Spent Fuel Storage Installation (ISFSI) operating licenses without the need to litigate contentions related to the continued storage of spent nuclear fuel on-site. This may facilitate potential future licensing needs for NSP-Minnesota.

See Notes 11 and 12 to the consolidated financial statements for further discussion regarding nuclear related items.

Nuclear Plant Power Upgrades and Life Extension

PI ISFSI License Renewal — The current license to operate an ISFSI at PI expired in October 2013. An application to renew the ISFSI license for an additional 40 years until 2053 was submitted by NSP-Minnesota to the NRC in October 2011. As PI met the NRC's criteria for timely renewal, it will be allowed to continue to operate under the current license until the NRC has rendered a decision on the license renewal application. The NRC's ASLB will establish a schedule for the hearing which should be completed by the second half of 2015.

Monticello Nuclear Uprate Project — NSP-Minnesota has received all federal and state approvals that are necessary and has completed all of the plant modifications to achieve the 71 MW capacity Monticello Nuclear Uprate Project and is in the process of completing the power ascension testing required by the NRC. Operation at the full increased power level is expected in the first half of 2015. As of Dec. 31, 2014, Monticello was operating at 656 MW, which includes approximately 56 MW of the extended uprate capacity. See Note 10 to the consolidated financial statements for further discussion.

Fuel Supply and Costs

The following table shows the delivered cost per MMBtu of each significant category of fuel consumed for owned electric generation, the percentage of total fuel requirements represented by each category of fuel and the total weighted average cost of all fuels.

NSP System Generating Plants	Coal ^(a)		Nuclear		Natural Gas		Weighted Average Owned Fuel Cost
	Cost	Percent	Cost	Percent	Cost	Percent	
2014	\$ 2.23	52%	\$ 0.89	42%	\$ 6.27	6%	\$ 1.94
2013	2.20	49	0.95	40	5.08	11	2.03
2012	2.13	47	0.90	42	4.21	11	1.88

(a) Includes refuse-derived fuel and wood.

The higher cost of natural gas was primarily due to higher market prices from increased demand because of cold weather in early 2014.

See Items 1A and 7 for further discussion of fuel supply and costs.

Fuel Sources

Coal — The NSP System normally maintains approximately 41 days of coal inventory. Coal supply inventories at Dec. 31, 2014 and 2013 were approximately 27 and 34 days usage, respectively. At Dec. 31, 2014, coal inventories were below optimal levels due to railcar congestion. NSP-Minnesota's generation stations use low-sulfur western coal purchased primarily under contracts with suppliers operating in Wyoming and Montana. During 2014 and 2013, coal requirements for the NSP System's major coal-fired generating plants were approximately 9.3 million tons and 7.3 million tons, respectively. Coal requirements for 2014 were higher as Sherco Unit 3 was placed back in service. The estimated coal requirements for 2015 are approximately 8.7 million tons, which reflects the retirement of Black Dog Units 3 and 4.

NSP-Minnesota and NSP-Wisconsin have contracted for coal supplies to provide 88 percent of their estimated coal requirements in 2015, and a declining percentage of the requirements in subsequent years. The NSP System's general coal purchasing objective is to contract for approximately 100 percent of requirements for the first year, 67 percent of requirements in year two, and 33 percent of requirements in year three. Remaining requirements will be filled through the procurement process or over-the-counter transactions.

NSP-Minnesota and NSP-Wisconsin have a number of coal transportation contracts that provide for delivery of 100 percent of their coal requirements in 2015 and 2016. Coal delivery may be subject to interruptions or reductions due to operation of the mines, transportation problems, weather and availability of equipment.

Nuclear — NSP-Minnesota secures contracts for uranium concentrates, uranium conversion, uranium enrichment and fuel fabrication to operate its' nuclear plants. The contract strategy involves a portfolio of spot purchases and medium and long-term contracts for uranium concentrates, conversion services and enrichment services with multiple producers and with a focus on diversification to minimize potential impacts caused by supply interruptions due to geographical and world political issues.

- Current nuclear fuel supply contracts cover 100 percent of uranium concentrates requirements through 2018 and approximately 72 percent of the requirements for 2019 through 2027.
- Current contracts for conversion services cover 100 percent of the requirements through 2021 and approximately 62 percent of the requirements for 2022 through 2027.
- Current enrichment service contracts cover 100 percent of the requirements through 2021 and approximately 68 percent of the requirements for 2025 through 2027.

Fabrication services for Monticello and PI are 100 percent committed through 2030 and 2019, respectively.

NSP-Minnesota expects sufficient uranium concentrates, conversion services and enrichment services to be available for the total fuel requirements of its nuclear generating plants. Some exposure to spot market price volatility will remain due to index-based pricing structures contained in certain supply contracts.

Natural gas — The NSP System uses both firm and interruptible natural gas supply and standby oil in combustion turbines and certain boilers. Natural gas supplies, transportation and storage services for power plants are procured under contracts to provide an adequate supply of fuel. However, as natural gas primarily serves intermediate and peak demand, remaining forecasted requirements are able to be procured through a liquid spot market. Generally, natural gas supply contracts have variable pricing that is tied to various natural gas indices. Most transportation contract pricing is based on FERC approved transportation tariff rates. Certain natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2014 and 2013, the NSP System did not have any commitments related to gas supply contracts; however commitments related to gas transportation and storage contracts were approximately \$349 million and \$389 million, respectively. Commitments related to gas transportation and storage contracts expire in various years from 2015 to 2028.

The NSP System also has limited on-site fuel oil storage facilities and primarily relies on the spot market for incremental supplies.

Renewable Energy Sources

The NSP System's renewable energy portfolio includes wind, hydroelectric, biomass and solar power from both owned generating facilities and PPAs. As of Dec. 31, 2014, the NSP System was in compliance with mandated RPS, which require generation from renewable resources of 18 percent and 12.9 percent of NSP-Minnesota and NSP-Wisconsin electric retail sales, respectively.

- Renewable energy comprised 24.2 percent and 22.9 percent of the NSP System's total owned and purchased energy for 2014 and 2013, respectively.
- Wind energy comprised 13.7 percent and 12.6 percent of the total owned and purchased energy on the NSP System for 2014 and 2013, respectively.
- Hydroelectric energy comprised 7.8 percent and 7.4 percent of the total owned and purchased energy on the NSP System for 2014 and 2013, respectively.
- Biomass and solar power comprised approximately 2.7 percent and 3.0 percent of the total owned and purchased energy on the NSP System for 2014 and 2013, respectively.

The NSP System also offers customer-focused renewable energy initiatives. Windsource® allows customers in Minnesota, Wisconsin, and Michigan to purchase a portion or all of their electricity from renewable sources. In 2014, the number of customers utilizing Windsource increased to approximately 43,000 from 37,000 in 2013. Windsource MWh sales increased from approximately 181,000 MWh in 2013 to 186,000 MWh in 2014.

Additionally, to encourage the growth of solar energy on the system, customers are offered incentives to install solar panels on their homes and businesses under the Solar*Rewards® program. Over 915 PV systems with approximately 11.1 MW of aggregate capacity and over 679 PV systems with approximately 7.3 MW of aggregate capacity have been installed in Minnesota under this program as of Dec. 31, 2014 and 2013, respectively.

As part of NSP-Minnesota's North Dakota 2013 electric rate case settlement, NSP-Minnesota is required to file a system restack proposal in 2015 to ensure that additional costs for compliance with Minnesota renewable initiatives are not paid for by North Dakota customers.

Wind — The NSP System acquires the majority of its wind energy from PPAs with wind farm owners, primarily located in Southwestern Minnesota. Currently, the NSP System has more than 100 of these agreements in place, with facilities ranging in size from under one MW to more than 200 MW. The NSP System owns and operates two wind farms which have the capacity to generate 302 MWs. Collectively, the NSP System had approximately 1,860 MWs of wind energy on its system at the end of 2014 and 2013. In October 2013, the MPUC approved four new projects, which are anticipated to provide up to 750 MW of capacity, including two projects totaling 350 MW that will be owned by NSP-Minnesota. One additional 20 MW project was approved in 2014. All five projects are targeted to be operational in late 2015. With the new projects, the NSP System is anticipated to have approximately 2,630 MWs of wind power. In addition to receiving purchased wind energy under these agreements, the NSP System also typically receives wind RECs, which are used to meet state renewable resource requirements. The average cost per MWh of wind energy under the existing contracts was approximately \$41 for 2014 and 2013. The cost per MWh of wind energy varies by contract and may be influenced by a number of factors including regulation, state-specific renewable resource requirements, and the year of contract execution. Generally, contracts executed in 2014 continued to benefit from improvements in technology, excess capacity among manufacturers, and motivation to commence new construction prior to the expiration of the Federal PTCs in 2014, with certain projects qualifying into future years.

Hydroelectric — The NSP System acquires its hydroelectric energy from both owned generation and PPAs. The NSP System owns 20 hydroelectric plants throughout Wisconsin and Minnesota which provide 268 MW of capacity. For 2014, PPAs provided approximately 38 MW of hydroelectric capacity. Additionally, the NSP System purchases approximately 850 MW of generation from Manitoba Hydro which is sourced primarily from its fleet of hydroelectric facilities.

Wholesale Commodity Marketing Operations

NSP-Minnesota conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy and energy-related products. See Item 7 for further discussion.

Summary of Recent Federal Regulatory Developments

The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, hydro facility licensing, natural gas transportation, asset transactions and mergers, accounting practices and certain other activities of NSP-Minnesota, including enforcement of NERC mandatory electric reliability standards. State and local agencies have jurisdiction over many of NSP-Minnesota's activities, including regulation of retail rates and environmental matters. In addition to the matters discussed below, see Note 10 to the accompanying consolidated financial statements for a discussion of other regulatory matters.

FERC Order, New ROE Policy — In June 2014, the FERC adopted a new two-step ROE methodology for electric utilities. In October 2014, the FERC upheld the determination of the long-term growth rate to be used in its new ROE methodology. Several parties sought rehearing of the June 2014 order and therefore the new FERC policy may be subject to additional changes.

FERC Order 1000, Transmission Planning and Cost Allocation (Order 1000) — In 2011, the FERC issued a final ruling, Order 1000, adopting new requirements for transmission planning, cost allocation and development to be effective prospectively. Order 1000 requires:

- The development of tariffs that provide for joint regional transmission planning and cost allocation for all FERC-jurisdictional utilities within a region;
- The coordination between regions for the development of interregional plans for transmission planning and cost allocation;
- Each public utility transmission provider to amend its Open Access Transmission Tariff to describe procedures that provide for the consideration of transmission needs driven by public policy requirements in the local and regional transmission planning processes; and
- The removal of ROFR provisions from FERC-jurisdictional wholesale transmission contracts and tariffs that presently grant the incumbent transmission owner a federal ROFR to build certain types of transmission projects in its service area.

MISO has submitted multiple compliance filings with the FERC to implement the Order 1000 requirements. Some of the new compliance provisions that were filed have already been approved but others remain under review by the FERC.

In August 2014, the D.C. Circuit denied all appeals and upheld Order 1000 in its entirety and indicated that challenges to the removal of federal ROFR provisions from individual contracts or tariffs could be considered in individual compliance filings. The FERC's decisions to remove federal ROFR provisions in certain MISO agreements were appealed to federal courts of appeal in 2014, and those appeals are pending. The removal of a federal ROFR would eliminate rights that NSP-Minnesota currently has under the MISO tariffs to build certain transmission projects within its footprint.

In 2014, MISO filed compliance plans that would allow the RTO to recognize state law ROFRs in any selection process for Order 1000 transmission projects. The MPUC, NDPSC and SDPUC granted this request in 2014. In 2015, the FERC issued orders on rehearing on the compliance filing that would continue to allow MISO the authority to recognize state ROFRs. NSP-Minnesota has state ROFRs in Minnesota, North Dakota and South Dakota.

Order 1000 could create opportunities for third parties to build and own certain regional transmission projects that had previously been reserved for the MISO transmission owners, potentially reducing NSP-Minnesota's financial return on new investments in electric transmission facilities. The ultimate impact of Order 1000 on future NSP-Minnesota transmission investment is not known at this time.

NERC Critical Infrastructure Protection Requirements — The FERC has approved version 5 of NERC’s critical infrastructure protection standards. Requirements must be applied to high and medium impact assets by April 1, 2016 and to low impact assets by April 1, 2017. NSP-Minnesota is currently in the process of evaluating the new requirements and identifying initiatives needed to meet the compliance deadlines.

NERC Physical Security Requirements — In November 2014, the FERC approved NERC’s proposed critical infrastructure protection standard related to physical security for bulk electric system facilities. The new standard will become enforceable in October 2015 with staggered milestone deliverable dates through 2016. NSP-Minnesota is currently in the process of developing and performing the initial risk assessment in accordance with the requirements of the standard, which will provide a basis to estimate the cost of protections necessary to meet the standard. The additional cost for compliance is anticipated to be recoverable through rates.

SPP and MISO Complaints Regarding RTO Joint Operating Agreement (JOA) — SPP and MISO have a longstanding dispute regarding the interpretation of their JOA, which is intended to coordinate RTO operations along the MISO/SPP system boundary. SPP and MISO disagree over MISO’s authority to transmit power over SPP transmission facilities between the traditional MISO region in the Midwest and the Entergy system. Several cases have been filed with the FERC by MISO and SPP. In June 2014, the FERC accepted a proposed tariff change by MISO to recover transmission charges imposed by SPP retroactive to January 2014, and set the issues for settlement judge and hearing procedures. If SPP is successful in charging MISO for use of the SPP system, the NSP System would experience higher costs from MISO, which could be material, but SPS would collect revenues from SPP. The outcome of the JOA disputes, and the potential impact on NSP-Minnesota, are uncertain at this time.

Xcel Energy Services Inc. and NSP-Wisconsin vs. ATC (La Crosse, Wis. to Madison, Wis. Transmission Line) — In February 2012, Xcel Energy Services Inc. and NSP-Wisconsin filed a complaint with the FERC concerning ownership of the proposed La Crosse, Wis. to Madison, Wis. 345 KV transmission line. In July 2012, the FERC ruled favorably on Xcel Energy Services Inc.’s and NSP-Wisconsin’s complaint, ruling that the responsibilities to construct the La Crosse, Wis. to Madison, Wis. transmission line, also known as the Badger Coulee line, belong equally to NSP-Wisconsin and ATC. In August 2012, ATC requested rehearing and requested that the FERC grant a stay of the ruling. ATC and NSP-Wisconsin jointly filed a CPCN application with the PSCW for the project in October 2013. In May 2014, the FERC issued an order denying the ATC request for rehearing and motion for stay. The 60 day period for ATC to appeal the FERC order lapsed, making the FERC ruling final.

MISO Transmission Pricing — The MISO Tariff presently provides for different allocation methods for the costs of new transmission investments depending on whether the project is primarily local or regional in nature. If a project qualifies as a MVP, the costs would be fully allocated to all loads in the MISO region. MVP eligibility is generally obtained for higher voltage (345 KV and higher) projects expected to serve multiple purposes, such as improved reliability, reduced congestion, transmission for renewable energy, and load serving.

Electric Operating Statistics

Electric Sales Statistics

	Year Ended Dec. 31		
	2014	2013	2012
Electric sales (Millions of KWh)			
Residential	10,317	10,486	10,377
Large commercial and industrial	8,859	8,963	9,302
Small commercial and industrial	15,670	15,577	15,478
Public authorities and other	264	267	264
Total retail	35,110	35,293	35,421
Sales for resale	2,704	1,397	1,625
Total energy sold	37,814	36,690	37,046
Number of customers at end of period			
Residential	1,274,182	1,263,575	1,252,589
Large commercial and industrial	466	483	496
Small commercial and industrial	153,988	152,769	151,978
Public authorities and other	7,015	6,869	6,699
Total retail	1,435,651	1,423,696	1,411,762
Wholesale	14	12	15
Total customers	1,435,665	1,423,708	1,411,777
Electric revenues (Thousands of Dollars)			
Residential	\$ 1,257,366	\$ 1,244,712	\$ 1,165,413
Large commercial and industrial	674,210	686,970	632,831
Small commercial and industrial	1,454,153	1,410,083	1,324,989
Public authorities and other	35,335	36,207	34,444
Total retail	3,421,064	3,377,972	3,157,677
Wholesale	92,326	47,511	42,748
Interchange revenues from NSP-Wisconsin	474,542	458,633	449,958
Other electric revenues	214,424	178,324	192,146
Total electric revenues	\$ 4,202,356	\$ 4,062,440	\$ 3,842,529
KWh sales per retail customer	24,456	24,790	25,090
Revenue per retail customer	\$ 2,383	\$ 2,373	\$ 2,237
Residential revenue per KWh	12.19 ¢	11.87 ¢	11.23 ¢
Large commercial and industrial revenue per KWh	7.61	7.66	6.80
Small commercial and industrial revenue per KWh	9.28	9.05	8.56
Total retail revenue per KWh	9.74	9.57	8.91
Wholesale revenue per KWh	3.41	3.40	2.63

Energy Source Statistics

NSP System	Year Ended Dec. 31					
	2014		2013		2012	
	Millions of KWh	Percent of Generation	Millions of KWh	Percent of Generation	Millions of KWh	Percent of Generation
Coal	18,079	39%	15,844	36%	16,023	35%
Nuclear	13,434	29	12,161	28	13,231	29
Natural Gas	3,402	7	5,550	13	6,200	13
Wind ^(a)	6,243	14	5,481	13	5,443	12
Hydroelectric	3,560	8	3,223	7	3,193	7
Other ^(b)	1,417	3	1,323	3	1,617	4
Total	46,135	100%	43,582	100%	45,707	100%
Owned generation	33,641	73%	29,249	67%	31,365	69%
Purchased generation	12,494	27	14,333	33	14,342	31
Total	46,135	100%	43,582	100%	45,707	100%

(a) This category includes wind energy de-bundled from RECs and also includes Windsources RECs. The NSP System uses RECs to meet or exceed state resource requirements and may sell surplus RECs.

(b) Includes energy from other sources, including solar, biomass, oil and refuse. Distributed generation from the Solar*Rewards program is not included, and was approximately seven, eight, and six net million KWh for 2014, 2013, and 2012, respectively.

NATURAL GAS UTILITY OPERATIONS

Overview

The most significant developments in the natural gas operations of NSP-Minnesota are continued volatility in natural gas market prices, uncertainty regarding political and regulatory developments that impact hydraulic fracturing, safety requirements for natural gas pipelines and the continued trend of declining use per residential customer, as a result of improved building construction technologies, higher appliance efficiencies and conservation. From 2000 to 2014, average annual sales to the typical residential customer declined 17 percent, while sales to the typical small C&I customer increased five percent, each on a weather-normalized basis. The increase in small C&I is due to new load growth. Although wholesale price increases do not directly affect earnings because of natural gas cost recovery mechanisms, high prices can encourage further efficiency efforts by customers.

The Pipeline and Hazardous Materials Safety Administration

Pipeline Safety Act — The Pipeline Safety, Regulatory Certainty, and Job Creation Act, signed into law in January 2012 (Pipeline Safety Act) requires additional verification of pipeline infrastructure records by pipeline owners and operators to confirm the maximum allowable operating pressure of lines located in high consequence areas or more-densely populated areas. The DOT Pipeline and Hazardous Materials Safety Administration (PHMSA) will require operators to re-confirm the maximum allowable operating pressure if records are inadequate. This process could cause temporary or permanent limitations on throughput for affected pipelines. In addition, the Pipeline Safety Act requires PHMSA to issue reports and develop new regulations including: requiring use of automatic or remote-controlled shut-off valves; requiring testing of certain previously untested transmission lines; and expanding integrity management requirements. The Pipeline Safety Act also raises the maximum penalty for violating pipeline safety rules to \$2 million per day for related violations. While NSP-Minnesota cannot predict the ultimate impact Pipeline Safety Act will have on its costs, operations or financial results, it is taking actions that are intended to comply with the Pipeline Safety Act and any related PHMSA regulations as they become effective. NSP-Minnesota can generally recover costs to comply with the transmission and distribution integrity management programs through the GUIC rider.

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — Retail rates, services and other aspects of NSP-Minnesota’s retail natural gas operations are regulated by the MPUC and the NDPSC within their respective states. The MPUC has regulatory authority over security issuances, certain property transfers, mergers with other utilities and transactions between NSP-Minnesota and its affiliates. In addition, the MPUC reviews and approves NSP-Minnesota’s natural gas supply plans for meeting customers’ future energy needs. NSP-Minnesota is subject to the jurisdiction of the FERC with respect to certain natural gas transactions in interstate commerce. NSP-Minnesota is subject to the DOT, the Minnesota Office of Pipeline Safety, the NDPSC and the SDPUC for pipeline safety compliance, including pipeline facilities used in electric utility operations for fuel deliveries.

Purchased Gas and Conservation Cost-Recovery Mechanisms — NSP-Minnesota’s retail natural gas rates for Minnesota and North Dakota include a PGA clause that provides for prospective monthly rate adjustments to reflect the forecasted cost of purchased natural gas, transportation service and storage service. The annual difference between the natural gas cost revenues collected through PGA rates and the actual natural gas costs is collected or refunded over the subsequent 12-month period.

NSP-Minnesota also recovers costs associated with transmission and distribution pipeline integrity management programs through its GUIC rider. Costs recoverable under the GUIC rider include funding for pipeline assessments as well as deferred costs from NSP-Minnesota’s existing sewer separation and pipeline integrity management programs. The MPUC and NDPSC have the authority to disallow recovery of certain costs if they find the utility was not prudent in its procurement activities.

Minnesota state law requires utilities to invest 0.5 percent of their state natural gas revenues in CIP. These costs are recovered through customer base rates and an annual cost-recovery mechanism for the CIP expenditures.

Capability and Demand

Natural gas supply requirements are categorized as firm or interruptible (customers with an alternate energy supply). The maximum daily send-out (firm and interruptible) for NSP-Minnesota was 752,931 MMBtu, which occurred on Jan. 2, 2014 and 767,636 MMBtu, which occurred on Jan. 21, 2013.

NSP-Minnesota purchases natural gas from independent suppliers, generally based on market indices that reflect current prices. The natural gas is delivered under transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of 610,048 MMBtu per day. In addition, NSP-Minnesota contracts with providers of underground natural gas storage services. These agreements provide storage for approximately 26 percent of winter natural gas requirements and 30 percent of peak day firm requirements of NSP-Minnesota.

NSP-Minnesota also owns and operates one LNG plant with a storage capacity of 2.0 Bcf equivalent and three propane-air plants with a storage capacity of 1.3 Bcf equivalent to help meet its peak requirements. These peak-shaving facilities have production capacity equivalent to 246,000 MMBtu of natural gas per day, or approximately 30 percent of peak day firm requirements. LNG and propane-air plants provide a cost-effective alternative to annual fixed pipeline transportation charges to meet the peaks caused by firm space heating demand on extremely cold winter days.

NSP-Minnesota is required to file for a change in natural gas supply contract levels to meet peak demand, to redistribute demand costs among classes, or to exchange one form of demand for another. In August 2014, the MPUC approved NSP-Minnesota’s contract demand levels for the years 2007 through 2013. Demand levels filed with the MPUC in 2014 are awaiting approval.

Natural Gas Supply and Costs

NSP-Minnesota actively seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio that provides increased flexibility, decreased interruption and financial risk and economical rates. In addition, NSP-Minnesota conducts natural gas price hedging activity that has been approved by the MPUC.

The following table summarizes the average delivered cost per MMBtu of natural gas purchased for resale by NSP-Minnesota's regulated retail natural gas distribution business:

2014	\$ 6.17
2013	4.53
2012	4.41

The higher cost of natural gas was primarily due to higher market prices from increased demand because of cold weather in early 2014.

NSP-Minnesota has firm natural gas transportation contracts with several pipelines, which expire in various years from 2015 through 2033.

NSP-Minnesota has certain natural gas supply, transportation and storage agreements that include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2014, NSP-Minnesota was committed to approximately \$294 million in such obligations under these contracts.

NSP-Minnesota purchases firm natural gas supply utilizing long-term and short-term agreements from approximately 31 domestic and Canadian suppliers. This diversity of suppliers and contract lengths allows NSP-Minnesota to maintain competition from suppliers and minimize supply costs.

See Items 1A and 7 for further discussion of natural gas supply and costs.

Natural Gas Operating Statistics

	Year Ended Dec. 31		
	2014	2013	2012
Natural gas deliveries (Thousands of MMBtu)			
Residential	45,044	42,446	32,817
Commercial and industrial	44,815	42,459	35,054
Total retail	89,859	84,905	67,871
Transportation and other	11,265	11,076	10,943
Total deliveries	101,124	95,981	78,814
Number of customers at end of period			
Residential	456,191	450,958	446,677
Commercial and industrial	42,504	41,929	41,542
Total retail	498,695	492,887	488,219
Transportation and other	24	24	21
Total customers	498,719	492,911	488,240
Natural gas revenues (Thousands of Dollars)			
Residential	\$ 412,723	\$ 329,810	\$ 263,233
Commercial and industrial	331,069	249,620	199,097
Total retail	743,792	579,430	462,330
Transportation and other	13,903	11,587	9,435
Total natural gas revenues	\$ 757,695	\$ 591,017	\$ 471,765
MMBtu sales per retail customer	180.19	172.26	139.02
Revenue per retail customer	\$ 1,491	\$ 1,176	\$ 947
Residential revenue per MMBtu	9.16	7.77	8.02
Commercial and industrial revenue per MMBtu	7.39	5.88	5.68
Transportation and other revenue per MMBtu	1.23	1.05	0.86

GENERAL

Seasonality

The demand for electric power and natural gas is affected by seasonal differences in the weather. In general, peak sales of electricity occur in the summer months, and peak sales of natural gas occur in the winter months. As a result, the overall operating results may fluctuate substantially on a seasonal basis. Additionally, NSP-Minnesota's operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. See Item 7 for further discussion.

Competition

NSP-Minnesota is a vertically integrated utility, subject to traditional cost-of-service regulation. However, NSP-Minnesota is subject to different public policies that promote competition and the development of energy markets. NSP-Minnesota's industrial and large commercial customers have the ability to own or operate facilities to generate their own electricity. In addition, customers may have the option of substituting other fuels, such as natural gas, steam or chilled water for heating, cooling and manufacturing purposes, or the option of relocating their facilities to a lower cost region. Customers also have the opportunity to supply their own power with on-site solar generation (typically rooftop solar) and in most jurisdictions can currently avoid paying for most of the fixed production, transmission and distribution costs incurred to serve them. Finally, customers can elect to subscribe to a community solar garden at pricing that affords them the same opportunity to avoid fixed charges as if they had rooftop installations.

The FERC has continued to promote competitive wholesale markets through open access transmission and other means. As a result, NSP-Minnesota and its wholesale customers can purchase generation resources from competing wholesale suppliers and use the transmission systems of Xcel Energy Inc.'s utility subsidiaries on a comparable basis to serve their native load. State public utilities commissions, including the MPUC, have created resource planning programs that promote competition in the acquisition of electricity generation resources used to provide service to retail customers. In addition, FERC Order 1000 seeks to establish competition for construction and operation of certain new electric transmission facilities. NSP-Minnesota has franchise agreements with certain cities subject to periodic renewal. If a city elected not to renew the franchise agreement, it could seek alternative means for its citizens to access electric power or gas, such as municipalization. Several states, including Minnesota, have policies designed to promote the development of solar and other distributed energy resources through significant incentive policies; with these incentives and federal tax subsidies, distributed generating resources are potential competitors to NSP-Minnesota's electric service business. While facing these challenges, NSP-Minnesota believes its rates and services are competitive with currently available alternatives.

ENVIRONMENTAL MATTERS

NSP-Minnesota's facilities are regulated by federal and state environmental agencies. These agencies have jurisdiction over air emissions, water quality, wastewater discharges, solid wastes and hazardous substances. Various company activities require registrations, permits, licenses, inspections and approvals from these agencies. NSP-Minnesota has received all necessary authorizations for the construction and continued operation of its generation, transmission and distribution systems. NSP-Minnesota's facilities have been designed and constructed to operate in compliance with applicable environmental standards. However, it is not possible to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of changes to environmental regulations, interpretations or enforcement policies or what effect future laws or regulations may have upon NSP-Minnesota's operations. See Notes 10 and 11 to the consolidated financial statements for further discussion.

There are significant future environmental regulations under consideration to encourage the use of clean energy technologies and regulate emissions of GHGs to address climate change. NSP-Minnesota has undertaken a number of initiatives to meet current requirements and prepare for potential future regulations, reduce GHG emissions and respond to state renewable and energy efficiency goals. If these future environmental regulations do not provide credit for the investments we have already made to reduce GHG emissions, or if they require additional initiatives or emission reductions, then their requirements would potentially impose additional substantial costs. We believe, based on prior state commission practice, we would recover the cost of these initiatives through rates.

EMPLOYEES

As of Dec. 31, 2014, NSP-Minnesota had 3,778 full-time employees and 15 part-time employees, of which 2,283 were covered under collective-bargaining agreements. See Note 7 to the consolidated financial statements for further discussion.

Item 1A — Risk Factors

Like other companies in our industry, Xcel Energy, which includes NSP-Minnesota, is subject to a variety of risks, many of which are beyond our control. Important risks that may adversely affect the business, financial condition, and results of operations are further described below. These risks should be carefully considered together with the other information set forth in this report and in future reports that Xcel Energy files with the SEC.

Oversight of Risk and Related Processes

A key accountability of the Board of Directors is to identify, manage and mitigate material risk. Our Board employs an effective process for doing so, combining management and Board risk oversight. The guidelines on corporate governance and Board committee charters define the scope of review and inquiry for the Board and its committees regarding risk management. As provided below, management and each committee has responsibility for overseeing aspects of risk management and mitigation of the risk.

Management identifies and analyzes risks to determine materiality and other attributes such as timing, probability and controllability, broadly considering our business, the utility industry, the domestic and global economy and the environment. Identification and analysis occurs formally through a key risk assessment process conducted by senior management, the financial disclosure process, the hazard risk management process and internal auditing and compliance with financial and operational controls. Management also identifies and analyzes risk through its business planning process and development of goals and key performance indicators, which include risk identification to determine barriers to implementing our strategy. At the same time, the business planning process identifies areas in which there is a potential for a business area to take inappropriate risk to meet goals and determines how to prevent inappropriate risk-taking.

At a threshold level, we have developed a robust compliance program and promote a culture of compliance, including tone at the top, which mitigates risk. The process for risk mitigation includes adherence to our code of conduct and other compliance policies, operation of formal risk management structures and groups, and overall business management to mitigate the risks inherent in the implementation strategy. Building on this culture of compliance, we manage and further mitigate risks through operation of formal risk management structures and groups, including management councils, risk committees and the services of internal corporate areas such as internal audit, the corporate controller and legal services.

Management communicates regularly with the Board and key stakeholders regarding risk. Senior management presents a periodic assessment of key risks to the Board. The presentation of the key risks and the discussion provides the Board with information on the risks management believes are material, including the earnings impact, timing, likelihood and controllability. Management also provides information to the Board in presentations and communications over the course of the year.

The Board has assigned several important aspects of its governance and oversight to four standing committees to ensure issues and risks are well understood and effectively managed. While the Board as a whole reviews management's key risk assessment and analyzes areas of potential future risk to Xcel Energy, the committees provide focused oversight of specific risks assigned to them. This provides robust and comprehensive risk management that is critical to successful execution of corporate strategy.

Risks Associated with Our Business

Environmental Risks

We are subject to environmental laws and regulations, with which compliance could be difficult and costly.

We are subject to environmental laws and regulations that affect many aspects of our past, present and future operations, including air emissions, water quality, wastewater discharges and the generation, transport and disposal of solid wastes and hazardous substances. These laws and regulations require us to obtain and comply with a wide variety of environmental requirements including those for protected natural and cultural resources (such as wetlands, endangered species and other protected wildlife, and archaeological and historical resources), licenses, permits, inspections and other approvals. Environmental laws and regulations can also require us to restrict or limit the output of certain facilities or the use of certain fuels, install pollution control equipment at our facilities, clean up spills and other contamination and correct environmental hazards. Environmental regulations may also lead to shutdown of existing facilities, either due to the difficulty in assuring compliance or that the costs of compliance no longer makes operation of the units economic. Both public officials and private individuals may seek to enforce the applicable environmental laws and regulations against us. We may be required to pay all or a portion of the cost to remediate (i.e., cleanup) sites where our past activities, or the activities of certain other parties, caused environmental contamination. At Dec. 31, 2014, these sites included:

- Sites of former MGPs operated by us, our predecessors, or other entities; and
- Third party sites, such as landfills, for which we are alleged to be a PRP that sent hazardous materials and wastes.

We are also subject to mandates to provide customers with clean energy, renewable energy and energy conservation offerings. Failure to meet the requirements of these mandates may result in fines or penalties, which could have a material effect on our results of operations. If our regulators do not allow us to recover all or a part of the cost of capital investment or the O&M costs incurred to comply with the mandates, it could have a material effect on our results of operations, financial position or cash flows.

In addition, existing environmental laws or regulations may be revised, and new laws or regulations seeking to protect the environment may be adopted or become applicable to us, including but not limited to, regulation of mercury, NO_x, SO₂, CO₂ and other GHGs, particulates and cooling water intake systems. We may also incur additional unanticipated obligations or liabilities under existing environmental laws and regulations.

We are subject to physical and financial risks associated with climate change.

There is a growing consensus that emissions of GHGs are linked to global climate change. Climate change creates physical and financial risk. Physical risks from climate change include changes in weather conditions, changes in precipitation and extreme weather events.

Our customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease. Increased energy use due to weather changes may require us to invest in additional generating assets, transmission and other infrastructure to serve increased load. Decreased energy use due to weather changes may affect our financial condition, through decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stress, including service interruptions. Weather conditions outside of our service territory could also have an impact on our revenues. We buy and sell electricity depending upon system needs and market opportunities. Extreme weather conditions creating high energy demand may raise electricity prices, which would increase the cost of energy we provide to our customers.

Severe weather impacts our service territories, primarily when thunderstorms, tornadoes and snow or ice storms occur. To the extent the frequency of extreme weather events increases, this could increase our cost of providing service. Changes in precipitation resulting in droughts or water shortages could adversely affect our operations, principally our fossil generating units. A negative impact to water supplies due to long-term drought conditions could adversely impact our ability to provide electricity to customers, as well as increase the price they pay for energy. We may not recover all costs related to mitigating these physical and financial risks.

To the extent climate change impacts a region's economic health, it may also impact our revenues. Our financial performance is tied to the health of the regional economies we serve. The price of energy, as a factor in a region's cost of living as well as an important input into the cost of goods and services, has an impact on the economic health of our communities. The cost of additional regulatory requirements, such as a tax on GHGs, regulation of CO₂ emissions under section 111(d) of the CAA, or additional environmental regulation could impact the availability of goods and prices charged by our suppliers which would normally be borne by consumers through higher prices for energy and purchased goods. To the extent financial markets view climate change and emissions of GHGs as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less than ideal terms and conditions.

Financial Risks

Our profitability depends in part on our ability to recover costs from our customers and there may be changes in circumstances or in the regulatory environment that impair our ability to recover costs from our customers.

We are subject to comprehensive regulation by federal and state utility regulatory agencies. The state utility commissions regulate many aspects of our utility operations, including siting and construction of facilities, customer service and the rates that we can charge customers. The FERC has jurisdiction, among other things, over wholesale rates for electric transmission service, the sale of electric energy in interstate commerce and certain natural gas transactions in interstate commerce.

The profitability of our operations is dependent on our ability to recover the costs of providing energy and utility services to our customers and earn a return on our capital investment in our utility operations. We provide service at rates approved by one or more regulatory commissions. These rates are generally regulated and based on an analysis of our costs incurred in a test year. Thus, the rates we are allowed to charge may or may not match our costs at any given time. While rate regulation is premised on providing an opportunity to earn a reasonable rate of return on invested capital, in a continued low interest rate environment there has been pressure pushing down ROE. There can also be no assurance that the applicable regulatory commission will judge all of our costs to have been prudent or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of our costs. Cost disallowances may arise as a result of prudence investigations (e.g., Monticello LCM/EPU project). Rising fuel costs could increase the risk that we will not be able to fully recover our fuel costs from our customers. Furthermore, there could be changes in the regulatory environment that would impair our ability to recover costs historically collected from our customers.

Management currently believes these prudently incurred costs are recoverable given the existing regulatory mechanisms in place. However, adverse regulatory rulings or the imposition of additional regulations, including additional environmental or climate change regulation, could have an adverse impact on our results of operations and hence could materially and adversely affect our ability to meet our financial obligations, including debt payments.

Any reductions in our credit ratings could increase our financing costs and the cost of maintaining certain contractual relationships.

We cannot be assured that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency. In addition, our credit ratings may change as a result of the differing methodologies or change in the methodologies used by the various rating agencies. Any downgrade could lead to higher borrowing costs. Also, we may enter into certain procurement and derivative contracts that require the posting of collateral or settlement of applicable contracts if credit ratings fall below investment grade.

We are subject to capital market and interest rate risks.

Utility operations require significant capital investment in property, plant and equipment. As a result, we frequently need to access the debt and equity capital markets. Any disruption in capital markets could have a material impact on our ability to fund our operations. Capital markets are global in nature and are impacted by numerous issues and events throughout the world economy. Capital market disruption events and resulting broad financial market distress could prevent us from issuing new securities or cause us to issue securities with less than ideal terms and conditions, such as higher interest rates.

Higher interest rates on short-term borrowings with variable interest rates or on incremental commercial paper issuances could also have an adverse effect on our operating results. Changes in interest rates may also impact the fair value of the debt securities in the nuclear decommissioning fund and master pension trust, as well as our ability to earn a return on short-term investments of excess cash.

We are subject to credit risks.

Credit risk includes the risk that our retail customers will not pay their bills, which may lead to a reduction in liquidity and an eventual increase in bad debt expense. Retail credit risk is comprised of numerous factors including the price of products and services provided, the overall economy and local economies in the geographic areas we serve, including local unemployment rates.

Credit risk also includes the risk that various counterparties that owe us money or product will breach their obligations. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected and we could incur losses.

One alternative available to address counterparty credit risk is to transact on liquid commodity exchanges. The credit risk is then socialized through the exchange central clearinghouse function. While exchanges do remove counterparty credit risk, all participants are subject to margin requirements, which create an additional need for liquidity to post margin as exchange positions change value daily. The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires broad clearing of financial swap transactions through a central counterparty, which could lead to additional margin requirements that would impact our liquidity. However, we have taken advantage of an exception to mandatory clearing afforded to commercial end-users who are not classified as a major swap participant. The Board of Directors has authorized Xcel Energy and its subsidiaries to take advantage of this end-user exception. In addition, the CFTC's rules permit us to deal in utility operations-related swaps with utility special entities and not be required to register as a swap dealer provided that our aggregate gross notional amount of swap dealing activity (including utility operations-related swaps) does not exceed the general de minimis threshold and provided that we have not exceeded the special entity de minimis threshold (excluding utility operations-related swaps) of \$25 million for the preceding 12 months. Our current level of financial swap activity with special entities is significantly below this special entity de minimis threshold; therefore, we will not be classified as a swap dealer in our special entity activity. Swap transactions with non-special entities have a much higher level of activity considered to be de minimis, currently \$8 billion, and our level of activity is well under this limit; therefore, we will not be classified as a swap dealer under the Dodd-Frank Act. We are currently reporting all of our swap transactions as part of the Dodd-Frank Act.

We may at times have direct credit exposure in our short-term wholesale and commodity trading activity to various financial institutions trading for their own accounts or issuing collateral support on behalf of other counterparties. We may also have some indirect credit exposure due to participation in organized markets, such as SPP, PJM and MISO, in which any credit losses are socialized to all market participants.

We do have additional indirect credit exposures to various domestic and foreign financial institutions in the form of letters of credit provided as security by power suppliers under various long-term physical purchased power contracts. If any of the credit ratings of the letter of credit issuers were to drop below the designated investment grade rating stipulated in the underlying long-term purchased power contracts, the supplier would need to replace that security with an acceptable substitute. If the security were not replaced, the party could be in technical default under the contract, which would enable us to exercise our contractual rights.

Increasing costs associated with our defined benefit retirement plans and other employee benefits may adversely affect our results of operations, financial position or liquidity.

We have defined benefit pension and postretirement plans that cover substantially all of our employees. Assumptions related to future costs, return on investments, interest rates and other actuarial assumptions have a significant impact on our funding requirements related to these plans. These estimates and assumptions may change based on economic conditions, actual stock and bond market performance, changes in interest rates and changes in governmental regulations. In addition, the Pension Protection Act changed the minimum funding requirements for defined benefit pension plans with modifications to these funding requirements that allowed additional flexibility in the timing of contributions. Therefore, our funding requirements and related contributions may change in the future. Also, the payout of a significant percentage of pension plan liabilities in a single year due to high retirements or employees leaving the company could trigger settlement accounting and could require the company to recognize material incremental pension expense related to unrecognized plan losses in the year these liabilities are paid.

Increasing costs associated with health care plans may adversely affect our results of operations.

Our self-insured costs of health care benefits for eligible employees have increased in recent years. Increasing levels of large individual health care claims and overall health care claims could have an adverse impact on our operating results, financial position and liquidity. We believe that our employee benefit costs, including costs related to health care plans for our employees and former employees, will continue to rise. Changes in industry standards utilized by management in key assumptions (e.g., mortality tables) could have a significant impact on future liabilities and benefit costs. Legislation related to health care could also significantly change our benefit programs and costs.

Operational Risks

We are subject to commodity risks and other risks associated with energy markets and energy production.

We engage in wholesale sales and purchases of electric capacity, energy and energy-related products as well as natural gas. As a result we are subject to market supply and commodity price risk. Commodity price changes can affect the value of our commodity trading derivatives. We mark certain derivatives to estimated fair market value on a daily basis (mark-to-market accounting). Actual settlements can vary significantly from estimated fair values recorded to the consolidated financial statements, and significant changes from the assumptions underlying our fair value estimates could cause significant earnings variability.

If we encounter market supply shortages or our suppliers are otherwise unable to meet their contractual obligations, we may be unable to fulfill our contractual obligations to our customers at previously authorized or anticipated costs. Any such disruption, if significant, would cause us to seek alternative supply services at potentially higher costs or suffer increased liability for unfulfilled contractual obligations. Any significantly higher energy or fuel costs relative to corresponding sales commitments would have a negative impact on our cash flows and could potentially result in economic losses. Potential market supply shortages may not be fully resolved through alternative supply sources and such interruptions may cause short-term disruptions in our ability to provide electric and/or natural gas services to our customers. The impact of these cost and reliability issues depends on our operating conditions such as generation fuels mix, availability of water for cooling, availability of fuel transportation including rail shipments of coal, electric generation capacity, transmission, natural gas pipeline capacity, etc.

We are subject to the risks of nuclear generation.

Our two nuclear stations, PI and Monticello, subject us to the risks of nuclear generation, which include:

- The risks associated with use of radioactive material in the production of energy, the management, handling, storage and disposal of these radioactive materials and the current lack of a long-term disposal solution for radioactive materials;
- Limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations; and
- Uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives.

The NRC has authority to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, until compliance is achieved. Revised NRC safety requirements could necessitate substantial capital expenditures or a substantial increase in operating expenses at our nuclear plants. In addition, the Institute for Nuclear Power Operations reviews our nuclear operations and nuclear generation facilities. Compliance with the Institute for Nuclear Power Operations' recommendations could result in substantial capital expenditures or a substantial increase in operating expenses.

If an incident did occur, it could have a material effect on our results of operations or financial condition. Furthermore, the non-compliance of other nuclear facilities operators with applicable regulations or the occurrence of a serious nuclear incident at other facilities could result in increased regulation of the industry as a whole, which could then increase our compliance costs and impact the results of operations of its facilities.

Our utility operations are subject to long-term planning risks.

Our utility operations file long-term resource plans with our regulators. These plans are based on numerous assumptions over the planning horizon such as: sales growth, customer usage, economic activity, costs, regulatory mechanisms, impact of technology, the installation of distributed generation, customer behavioral response and continuation of the existing utility business model. Given the uncertainty in these planning assumptions, there is a risk that the magnitude and timing of resource additions and demand may not coincide. NSP-Minnesota's aging infrastructure may pose a risk to system reliability and expose us to premature financial obligations. NSP-Minnesota is engaged in significant and ongoing infrastructure investment programs.

In addition, large industrial customers may leave our system and invest in their own on-site distributed generation or seek law changes to give them the authority to purchase directly from other suppliers or organized markets. The recent low natural gas price environment has caused some customers to consider their options in this area, particularly customers with industrial processes using steam. Wholesale customers may purchase directly from other suppliers and procure only transmission service from us. These circumstances provide for greater long-term planning uncertainty related to future load growth. Similarly, distributed solar generation may become an economic competitive threat to our load growth in the future. However, we believe the economics, absent significant subsidies, do not support such a trend in the near term unless a state mandates the purchase of such generation. Some states have considered such legislation.

Our natural gas transmission and distribution operations involve numerous risks that may result in accidents and other operating risks and costs.

Our natural gas transmission and distribution activities include a variety of inherent hazards and operating risks, such as leaks, explosions and mechanical problems, which could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution, impairment of our operations and substantial losses to us. We maintain insurance against some, but not all, of these risks and losses.

The occurrence of any of these events not fully covered by insurance could have a material effect on our financial position and results of operations. For our natural gas transmission or distribution lines located near populated areas the level of potential damages resulting from these risks is greater.

Additionally, the operating or other costs that may be required in order to comply with potential new regulations, including the Pipeline Safety Act, could be significant. The Pipeline Safety Act requires verification of pipeline infrastructure records by intrastate and interstate pipeline owners and operators to confirm the maximum allowable operating pressure of lines located in high consequence areas or more-densely populated areas. We have programs in place to comply with the Pipeline Safety Act and for systematic infrastructure monitoring and renewal over time. A significant incident could increase regulatory scrutiny and result in penalties and higher costs of operations.

As we are a subsidiary of Xcel Energy Inc., we may be negatively affected by events impacting the credit or liquidity of Xcel Energy Inc. and its affiliates.

If Xcel Energy Inc. were to become obligated to make payments under various guarantees and bond indemnities or to fund its other contingent liabilities, or if either Standard & Poor's or Moody's were to downgrade Xcel Energy Inc.'s credit rating below investment grade, Xcel Energy Inc. may be required to provide credit enhancements in the form of cash collateral, letters of credit or other security to satisfy part or potentially all of these exposures. If either Standard & Poor's or Moody's were to downgrade Xcel Energy Inc.'s debt securities below investment grade, it would increase Xcel Energy Inc.'s cost of capital and restrict its access to the capital markets. This could limit Xcel Energy Inc.'s ability to contribute equity or make loans to us, or may cause Xcel Energy Inc. to seek additional or accelerated funding from us in the form of dividends. If such event were to occur, we may need to seek alternative sources of funds to meet our cash needs.

As of Dec. 31, 2014, Xcel Energy Inc. and its utility subsidiaries had approximately \$11.5 billion of long-term debt and \$1.3 billion of short-term debt and current maturities. Xcel Energy Inc. provides various guarantees and bond indemnities supporting some of its subsidiaries by guaranteeing the payment or performance by these subsidiaries for specified agreements or transactions.

Xcel Energy also has other contingent liabilities resulting from various tax disputes and other matters. Xcel Energy Inc.'s exposure under the guarantees is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. The majority of Xcel Energy Inc.'s guarantees limit its exposure to a maximum amount that is stated in the guarantees. As of Dec. 31, 2014, Xcel Energy had guarantees outstanding with a maximum stated amount of approximately \$13.9 million and \$0.2 million of exposure. Xcel Energy also had additional guarantees of \$31.4 million at Dec. 31, 2014 for performance and payment of surety bonds for the benefit of itself and its subsidiaries, with total exposure that cannot be estimated at this time. If Xcel Energy Inc. were to become obligated to make payments under these guarantees and bond indemnities or become obligated to fund other contingent liabilities, it could limit Xcel Energy Inc.'s ability to contribute equity or make loans to us, or may cause Xcel Energy Inc. to seek additional or accelerated funding from us in the form of dividends. If such event were to occur, we may need to seek alternative sources of funds to meet our cash needs.

We are a wholly owned subsidiary of Xcel Energy Inc. Xcel Energy Inc. can exercise substantial control over our dividend policy and business and operations and may exercise that control in a manner that may be perceived to be adverse to our interests.

All of the members of our Board of Directors, as well as many of our executive officers, are officers of Xcel Energy Inc. Our Board makes determinations with respect to a number of significant corporate events, including the payment of our dividends.

We have historically paid quarterly dividends to Xcel Energy Inc. In 2014, 2013 and 2012 we paid \$259.5 million, \$235.5 million and \$234.1 million of dividends to Xcel Energy Inc., respectively. If Xcel Energy Inc.'s cash requirements increase, our Board of Directors could decide to increase the dividends we pay to Xcel Energy Inc. to help support Xcel Energy Inc.'s cash needs. This could adversely affect our liquidity. The most restrictive dividend limitation for NSP-Minnesota is imposed by our state regulatory commissions. State regulatory commissions indirectly limit the amount of dividends NSP-Minnesota can pay to Xcel Energy Inc., by requiring a minimum equity-to-total capitalization ratio. See Item 5 for further discussion on dividend limitations.

Public Policy Risks

We may be subject to legislative and regulatory responses to climate change and emissions, with which compliance could be difficult and costly.

Increased public awareness and concern regarding climate change may result in more regional and/or federal requirements to reduce or mitigate the effects of GHGs. Legislative and regulatory responses related to climate change and new interpretations of existing laws through climate change litigation create financial risk as our electric generating facilities may be subject to additional regulation under climate change laws at either the state or federal level in the future. The EPA is regulating GHGs under the CAA. The EPA has regulated GHG emissions from motor vehicles and has proposed regulations to reduce GHG emissions from existing power plants that are expected to become final in 2015, with state plans to achieve the EPA's goals due by 2017. Such regulations could impose substantial costs on our system. The EPA has also proposed regulations that would establish NSPS for any new fossil fuel-fired power plants that may be built which may be adopted in 2015. If adopted, these regulations could significantly increase the cost of building new generating plants.

The United States continues to participate in international negotiations related to the United Nations Framework Convention on Climate Change (UNFCCC). In 2014, the United States and China jointly announced GHG emissions goals. Further, the 20th Conference of the Parties (COP) to the UNFCCC concluded with the objective of developing an agreement among countries on emission reductions at the 2015 COP. This could result in additional GHG regulation or reduction goals in the United States.

We have been, and in the future may be subject to climate change lawsuits. An adverse outcome in any of these cases could require substantial capital expenditures and could possibly require payment of substantial penalties or damages. Defense costs associated with such litigation can also be significant. Such payments or expenditures could affect results of operations, cash flows and financial condition if such costs are not recovered through regulated rates.

There are many uncertainties regarding when and in what form climate change legislation or regulations will be imposed. The impact of legislation and regulations will depend on a number of factors, including what GHG emission reduction goals are set, what flexibility is allowed to meet the goals, how and whether early action to reduce GHG emissions is credited, whether GHG sources in other sectors of the economy are regulated, the degree to which GHG offsets are recognized as compliance options, how any emission allowances would be allocated to specific sources and the indirect impact of carbon regulation on natural gas and coal prices. In addition, international treaties or accords could have an impact to the extent they lead to future federal or state regulations. Another important factor is our ability to recover the costs incurred to comply with any regulatory requirements in a timely manner. If our regulators do not allow us to recover all or a part of the cost of capital investment or the O&M costs incurred to comply with the mandates, it could have a material effect on our results of operations.

We are also subject to a significant number of proposed and potential rules that will impact our coal-fired and other generation facilities. These include rules associated with emissions of SO₂ and NO_x, mercury, regional haze, ozone and particulate matter, water discharges and ash management. The costs of investment to comply with these rules could be substantial and in some cases would lead to early retirement of coal units. We may not be able to timely recover all costs related to complying with regulatory requirements imposed on us.

Increased risks of regulatory penalties could negatively impact our business.

The Energy Act increased civil penalty authority for violation of FERC statutes, rules and orders. The FERC can now impose penalties of up to \$1 million per violation per day. In addition, NERC electric reliability standards are now mandatory and subject to potential financial penalties by regional entities, the NERC or the FERC for violations. If a serious reliability incident did occur, it could have a material effect on our operations or financial results. Some states have the authority to impose substantial penalties in the event of non-compliance.

We attempt to mitigate the risk of regulatory penalties through formal training on such prohibited practices and a compliance function that reviews our interaction with the markets under FERC and CFTC jurisdictions. However, there is no guarantee our compliance program will be sufficient to ensure against violations.

Macroeconomic Risks

Economic conditions impact our business.

Our operations are affected by local, national and worldwide economic conditions both positively and negatively. Growth in our customer base is correlated with economic conditions. While the number of customers is growing, sales growth is relatively modest due to an increased focus on energy efficiency including federal standards for appliance and lighting efficiency and distributed generation, primarily solar PV. Instability in the financial markets also may affect the cost of capital and our ability to raise capital, which are discussed in the capital market risk section above.

Economic conditions may be impacted by insufficient financial sector liquidity leading to potential increased unemployment, which may impact customers' ability to pay timely, increase customer bankruptcies, and may lead to increased bad debt.

Further, worldwide economic activity has an impact on the demand for basic commodities needed for utility infrastructure, such as steel, copper, aluminum, etc., which may impact our ability to acquire sufficient supplies. Additionally, the cost of those commodities may be higher than expected.

Our operations could be impacted by war, acts of terrorism, threats of terrorism or disruptions in normal operating conditions due to localized or regional events.

Our generation plants, fuel storage facilities, transmission and distribution facilities and information systems may be targets of terrorist activities that could disrupt our ability to produce or distribute some portion of our energy products. Any such disruption could result in a decrease in revenues and additional costs to repair and insure our assets. These disruptions could have a material impact on our financial condition and results of operations. The potential for terrorism has subjected our operations to increased risks and could have a material effect on our business. We have already incurred increased costs for security and capital expenditures in response to these risks. In addition, we may experience additional capital and operating costs to implement security for our plants, including our nuclear power plants under the NRC's design basis threat requirements. We have also already incurred increased costs for compliance with NERC reliability standards associated with critical infrastructure protection, and may experience additional capital and operating costs to comply with the NERC critical infrastructure protection standards as they are implemented and clarified.

The insurance industry has also been affected by these events and the availability of insurance may decrease. In addition, the insurance we are able to obtain may have higher deductibles, higher premiums and more restrictive policy terms.

A disruption of the regional electric transmission grid, interstate natural gas pipeline infrastructure or other fuel sources, could negatively impact our business. Because our generation, transmission systems and local natural gas distribution companies are part of an interconnected system, we face the risk of possible loss of business due to a disruption caused by the actions of a neighboring utility or an event (severe storm, severe temperature extremes, generator or transmission facility outage, pipeline rupture, railroad disruption, sudden and significant increase or decrease in wind generation, or any disruption of work force such as may be caused by flu or other epidemic) within our operating systems or on a neighboring system. Any such disruption could result in a significant decrease in revenues and significant additional costs to repair assets, which could have a material impact on our financial condition and results.

The degree to which we are able to maintain day-to-day operations in response to unforeseen events will in part determine the financial impact of certain events on our financial condition and results. It is difficult to predict the magnitude of such events and associated impacts.

A cyber incident or cyber security breach could have a material effect on our business.

We operate in an industry that requires the continued operation of sophisticated information technology systems and network infrastructure. In addition, we use our systems and infrastructure to create, collect, use, disclose, store, dispose of and otherwise process sensitive information, including company data, customer energy usage data, and personal information regarding customers, employees and their dependents, contractors and other individuals.

Our generation, transmission, distribution and fuel storage facilities, information technology systems and other infrastructure or physical assets, as well as the information processed in our systems (e.g., information about our customers, employees, operations, infrastructure and assets) could be affected by cyber security incidents, including those caused by human error. Our industry has begun to see an increased volume and sophistication of cyber security incidents from international activist organizations, Nation States, and individuals. Cyber security incidents could harm our businesses by limiting our generating, transmitting and distributing capabilities, delaying our development and construction of new facilities or capital improvement projects to existing facilities, disrupting our customer operations, or exposing us to liability. Our generation, transmission systems and natural gas pipelines are part of an interconnected system. Therefore, a disruption caused by the impact of a cyber security incident of the regional electric transmission grid, natural gas pipeline infrastructure or other fuel sources of our third party service providers' operations, could also negatively impact our business. In addition, such an event would likely receive regulatory scrutiny at both the federal and state level. We are unable to quantify the potential impact of cyber security threats or subsequent related actions. These potential cyber security incidents and corresponding regulatory action could result in a material decrease in revenues and may cause significant additional costs (e.g., penalties, third party claims, repairs, insurance or compliance) and potentially disrupt our supply and markets for natural gas, oil and other fuels.

We maintain security measures designed to protect our information technology systems, network infrastructure and other assets. However, these assets and the information they process may be vulnerable to cyber security incidents, including the resulting disability, or failures of assets or unauthorized access to assets or information. If our technology systems were to fail or be breached, or those of our third-party service providers, we may be unable to fulfill critical business functions, including effectively maintaining certain internal controls over financial reporting. We are unable to quantify the potential impact of cyber security incidents on our business.

Rising energy prices could negatively impact our business.

While we have fuel clause recovery mechanisms, higher fuel costs could significantly impact our results of operations if costs are not recovered. In addition, higher fuel costs could reduce customer demand and/or increase bad debt expense, which could also have a material impact on our results of operations. Delays in the timing of the collection of fuel cost recoveries as compared with expenditures for fuel purchases could have an impact on our cash flows. We are unable to predict future prices or the ultimate impact of such prices on our results of operations or cash flows.

Our operating results may fluctuate on a seasonal and quarterly basis and can be adversely affected by milder weather.

Our electric and natural gas utility businesses are seasonal, and weather patterns can have a material impact on our operating performance. Demand for electricity is often greater in the summer and winter months associated with cooling and heating. Because natural gas is heavily used for residential and commercial heating, the demand for this product depends heavily upon weather patterns throughout our service territory, and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. Unusually mild winters and summers could have an adverse effect on our financial condition, results of operations, or cash flows.

Item 1B — Unresolved Staff Comments

None.

Item 2 — Properties

Virtually all of the utility plant property of NSP-Minnesota is subject to the lien of its first mortgage bond indenture.

Electric Utility Generating Stations:

Station, Location and Unit	Fuel	Installed	Summer 2014 Net Dependable Capability (MW)
Steam:			
A.S. King-Bayport, Minn., 1 Unit	Coal	1968	511
Sherco-Becker, Minn.			
Unit 1	Coal	1976	680
Unit 2	Coal	1977	682
Unit 3	Coal	1987	507 ^(a)
Monticello-Monticello, Minn., 1 Unit	Nuclear	1971	554
PI-Welch, Minn.			
Unit 1	Nuclear	1973	521
Unit 2	Nuclear	1974	519
Black Dog-Burnsville, Minn., 2 Units	Coal/Natural Gas	1955-1960	215
Various locations, 4 Units	Wood/Refuse-derived fuel	Various	36 ^(b)
Combustion Turbine:			
Angus Anson-Sioux Falls, S.D., 3 Units	Natural Gas	1994-2005	327
Black Dog-Burnsville, Minn., 2 Units	Natural Gas	1987-2002	271
Blue Lake-Shakopee, Minn., 6 Units	Natural Gas	1974-2005	453
High Bridge-St. Paul, Minn., 3 Units	Natural Gas	2008	534
Inver Hills-Inver Grove Heights, Minn., 6 Units	Natural Gas	1972	282
Riverside-Minneapolis, Minn., 3 Units	Natural Gas	2009	470
Various locations, 17 Units	Natural Gas	Various	101
Wind:			
Grand Meadow-Mower County, Minn., 67 Units	Wind	2008	101 ^(c)
Nobles-Nobles County, Minn., 134 Units	Wind	2010	201 ^(c)
		Total	<u>6,965</u>

(a) Based on NSP-Minnesota's ownership of 59 percent.

(b) Refuse-derived fuel is made from municipal solid waste.

(c) This capacity is only available when wind conditions are sufficiently high enough to support the noted generation values above. Therefore, the on-demand net dependable capacity is zero.

Electric utility overhead and underground transmission and distribution lines (measured in conductor miles) at Dec. 31, 2014:

Conductor Miles	
500 KV	2,917
345 KV	8,403
230 KV	1,803
161 KV	416
115 KV	7,502
Less than 115 KV	84,090

NSP-Minnesota had 356 electric utility transmission and distribution substations at Dec. 31, 2014.

Natural gas utility mains at Dec. 31, 2014:

Miles	
Transmission	136
Distribution	9,931

Item 3 — Legal Proceedings

NSP-Minnesota is involved in various litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

Additional Information

See Note 11 to the consolidated financial statements for further discussion of legal claims and environmental proceedings. See Item 1 and Note 10 to the consolidated financial statements for a discussion of proceedings involving utility rates and other regulatory matters.

Item 4 — Mine Safety Disclosures

None.

PART II

Item 5 — Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

NSP-Minnesota is a wholly owned subsidiary of Xcel Energy Inc. and there is no market for its common equity securities.

NSP-Minnesota’s first mortgage indenture places certain restrictions on the amount of cash dividends it can pay to Xcel Energy Inc., the holder of its common stock. Even with this restriction, NSP-Minnesota could have paid more than \$1.6 billion and \$1.4 billion in additional cash dividends on common stock at Dec. 31, 2014 and 2013, respectively.

In addition, NSP-Minnesota has dividend restrictions imposed by FERC rules and state regulatory commissions:

- Dividends are subject to the FERC’s jurisdiction under the Federal Power Act, which prohibits the payment of dividends out of capital accounts; payment of dividends is allowed out of retained earnings only.
- The most restrictive dividend limitation for NSP-Minnesota is imposed by its state regulatory commissions. NSP-Minnesota’s state regulatory commissions indirectly limit the amount of dividends NSP-Minnesota can pay to Xcel Energy Inc. by requiring an equity-to-total capitalization ratio between 47.1 percent and 57.5 percent. NSP-Minnesota’s equity-to-capitalization ratio was 52.1 percent at Dec. 31, 2014 and \$848 million in retained earnings was not restricted. Total capitalization for NSP-Minnesota was \$9.0 billion at Dec. 31, 2014, which did not exceed the limits imposed by the commissions of \$9.5 billion.

See Note 4 to the consolidated financial statements for further discussion of NSP-Minnesota’s dividend policy.

The dividends declared during 2014 and 2013 were as follows:

(Thousands of Dollars)	2014	2013
First quarter	\$ 59,740	\$ 58,690
Second quarter	73,750	59,308
Third quarter	67,210	58,744
Fourth quarter	77,802	58,751

Item 6 — Selected Financial Data

This is omitted per conditions set forth in general instructions I(1)(a) and (b) of Form 10-K for wholly owned subsidiaries (reduced disclosure format).

Item 7 — Management’s Discussion and Analysis of Financial Condition and Results of Operations

Discussion of financial condition and liquidity for NSP-Minnesota is omitted per conditions set forth in general instructions I(1)(a) and (b) of Form 10-K for wholly owned subsidiaries. It is replaced with management’s narrative analysis and the results of operations for the current year as set forth in general instructions I(2)(a) of Form 10-K for wholly owned subsidiaries (reduced disclosure format).

Financial Review

The following discussion and analysis by management focuses on those factors that had a material effect on NSP-Minnesota’s financial condition, results of operations and cash flows during the periods presented, or are expected to have a material impact in the future. It should be read in conjunction with the accompanying consolidated financial statements and related notes to the consolidated financial statements.

Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed in the following discussion and analysis are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words “anticipate,” “believe,” “estimate,” “expect,” “intend,” “may,” “objective,” “outlook,” “plan,” “project,” “possible,” “potential,” “should” and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made and we do not undertake any obligation to update them to reflect changes that occur after that date. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of NSP-Minnesota and its subsidiaries to obtain financing on favorable terms; business conditions in the energy industry, including the risk of a slowdown in the U.S. economy or delay in growth recovery; trade, fiscal, taxation and environmental policies in areas where NSP-Minnesota has a financial interest; customer business conditions; actions of credit rating agencies; competitive factors, including the extent and timing of the entry of additional competition in the markets served by NSP-Minnesota and its subsidiaries; unusual weather; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates or have an impact on asset operation or ownership or impose environmental compliance conditions; structures that affect the speed and degree to which competition enters the electric and natural gas markets; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; actions by regulatory bodies impacting NSP-Minnesota’s nuclear operations, including those affecting costs, operations or the approval of requests pending before the NRC; financial or regulatory accounting policies imposed by regulatory bodies; availability or cost of capital; employee workforce factors; and the other risk factors listed from time to time by NSP-Minnesota in reports filed with the SEC, including “Risk Factors” in Item 1A of this Annual Report on Form 10-K and Exhibit 99.01 hereto.

Results of Operations

NSP-Minnesota’s net income was approximately \$404.9 million for 2014, compared with approximately \$393.3 million for 2013. Earnings were positively impacted by electric rate increases in Minnesota (interim, subject to refund) and North Dakota and weather-normalized sales growth. These items were partially offset by higher O&M expenses, the unfavorable impact of weather, lower AFUDC and increased property taxes and interest charges.

Electric Revenues and Margin

Electric revenues and fuel and purchased power expenses are largely impacted by the fluctuation in the price of natural gas, coal and uranium used in the generation of electricity, but as a result of the design of fuel recovery mechanisms to recover current expenses, these price fluctuations have minimal impact on electric margin. The following table details the electric revenues and margin:

(Millions of Dollars)	2014	2013
Electric revenues	\$ 4,202	\$ 4,062
Electric fuel and purchased power	(1,676)	(1,684)
Electric margin	\$ 2,526	\$ 2,378

The following tables summarize the components of the changes in electric revenues and electric margin for the year ended Dec. 31:

Electric Revenues

(Millions of Dollars)	2014 vs. 2013
Retail rate increases ^(a)	\$ 60
Trading	44
Conservation program revenues (offset by expenses)	39
Non-fuel riders	33
Transmission revenue	17
Interchange revenues from NSP-Wisconsin	16
Fuel and purchased power cost recovery	(59)
Estimated impact of weather	(24)
Other, net	14
Total increase in electric revenues	<u>\$ 140</u>

Electric Margin

(Millions of Dollars)	2014 vs. 2013
Retail rate increases ^(a)	\$ 60
Conservation program revenues (offset by expenses)	39
Non-fuel riders	33
Interchange revenues from NSP-Wisconsin	24
Estimated impact of weather	(24)
Other, net	16
Total increase in electric margin	<u>\$ 148</u>

(a) The retail rate increases include final rates in North Dakota and interim rates in Minnesota, subject to and net of estimated provision for refund. See Note 10 to the consolidated financial statements.

Natural Gas Revenues and Margin

The cost of natural gas tends to vary with changing sales requirements and the cost of natural gas purchases. However, due to the design of purchased natural gas cost recovery mechanisms to recover current expenses for sales to retail customers, fluctuations in the cost of natural gas have little effect on natural gas margin. The following table details natural gas revenues and margin:

(Millions of Dollars)	2014	2013
Natural gas revenues	\$ 758	\$ 591
Cost of natural gas sold and transported	(532)	(380)
Natural gas margin	<u>\$ 226</u>	<u>\$ 211</u>

The following tables summarize the components of the changes in natural gas revenues and natural gas margin for the year ended Dec. 31:

Natural Gas Revenues

(Millions of Dollars)	2014 vs. 2013
Purchased natural gas adjustment clause recovery	\$ 153
Estimated impact of weather	5
Retail sales growth, excluding weather impact	3
Conservation program revenues (offset by expenses)	2
Other, net	4
Total increase in natural gas revenues	<u>\$ 167</u>

Natural Gas Margin

(Millions of Dollars)	2014 vs. 2013
Estimated impact of weather	\$ 5
Retail sales growth, excluding weather impact	3
Conservation program revenues (offset by expenses)	2
Other, net	5
Total increase in natural gas margin	\$ 15

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses increased \$52.0 million, or 4.4 percent, for 2014 compared with 2013. The following table summarizes the changes in O&M expenses for the year ended Dec. 31:

(Millions of Dollars)	2014 vs. 2013
Nuclear plant operations and amortization	\$ 36
Interchange agreement billing with NSP-Wisconsin	8
Employee benefits	6
Other, net	2
Total increase in O&M expenses	\$ 52

- Nuclear cost increases are related to the amortization of prior outages and initiatives designed to improve the operational efficiencies of the plants.

Conservation Program Expenses — Conservation program expenses increased \$41.5 million, or 42.9 percent, for 2014 compared with 2013. This increase was primarily attributable to higher electric recovery rates. Conservation program expenses are generally recovered in our major jurisdictions concurrently through riders and base rates.

Depreciation and Amortization — Depreciation and amortization expense decreased \$3.7 million, or 0.9 percent, for 2014 compared with 2013. The decrease was primarily attributable to additional accelerated amortization of the excess depreciation reserve associated with certain Minnesota assets, partially offset by the PI steam generator replacement placed in service in December 2013 and normal system expansion. See further discussion within Note 10 to the consolidated financial statements.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased \$15.1 million, or 7.3 percent, for 2014 compared with 2013. The increase was primarily due to higher property taxes in Minnesota.

AFUDC, Equity and Debt — AFUDC decreased \$23.6 million for 2014 compared with 2013. The decrease is primarily due to the portion of the Monticello LCM/EPU placed in service in July 2013 and the PI steam generator replacement placed in service in December 2013, partially offset by the expansion of transmission facilities.

Interest Charges — Interest charges increased \$7.8 million, or 4.1 percent, for 2014 compared with 2013. The increase is primarily due to higher long-term debt levels, partially offset by refinancings at lower interest rates and interest on customer refunds in Minnesota.

Income Taxes — Income tax expense increased \$16.2 million for 2014 compared with 2013. The increase in income tax expense was primarily due to higher pretax earnings and decreased permanent plant-related adjustments in 2014. These were partially offset by a 2014 tax benefit for prior year adjustments. The ETR was 32.9 percent for 2014 compared with 31.6 percent for 2013 due to these adjustments.

Item 7A — Quantitative and Qualitative Disclosures About Market Risk

Derivatives, Risk Management and Market Risk

NSP-Minnesota is exposed to a variety of market risks in the normal course of business. Market risk is the potential loss that may occur as a result of adverse changes in the market or fair value of a particular instrument or commodity. All financial and commodity-related instruments, including derivatives, are subject to market risk. See Note 9 to the consolidated financial statements for further discussion of market risks associated with derivatives.

NSP-Minnesota is exposed to the impact of adverse changes in price for energy and energy related products, which is partially mitigated by the use of commodity derivatives. In addition to ongoing monitoring and maintaining credit policies intended to minimize overall credit risk, when necessary, management takes steps to mitigate changes in credit and concentration risks associated with its derivatives and other contracts, including parental guarantees and requests of collateral. While NSP-Minnesota expects that the counterparties will perform under the contracts underlying its derivatives, the contracts expose NSP-Minnesota to some credit and nonperformance risk.

Though no material non-performance risk currently exists with the counterparties to NSP-Minnesota's commodity derivative contracts, distress in the financial markets may in the future impact that risk to the extent it impacts those counterparties. Distress in the financial markets may also impact the fair value of the securities in the nuclear decommissioning fund and master pension trust, as well as NSP-Minnesota's ability to earn a return on short-term investments of excess cash.

Commodity Price Risk — NSP-Minnesota is exposed to commodity price risk in its electric and natural gas operations. Commodity price risk is managed by entering into short- and long-term physical purchase and sales contracts for electric capacity, energy and energy-related products and for various fuels used in generation and distribution activities. Commodity price risk is also managed through the use of financial derivative instruments. NSP-Minnesota's risk management policy allows it to manage commodity price risk within each rate-regulated operation to the extent such exposure exists.

Wholesale and Commodity Trading Risk — NSP-Minnesota conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments. NSP-Minnesota's risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee, which is made up of management personnel not directly involved in the activities governed by this policy.

At Dec. 31, 2014, the fair values by source for net commodity trading contract assets were as follows:

Futures / Forwards						
(Thousands of Dollars)	Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Futures/ Forwards Fair Value
NSP-Minnesota	1	\$ 6,359	\$ 8,238	\$ 1,401	\$ 1,088	\$ 17,086
	2	4,400	—	—	—	4,400
		<u>\$ 10,759</u>	<u>\$ 8,238</u>	<u>\$ 1,401</u>	<u>\$ 1,088</u>	<u>\$ 21,486</u>
Options						
(Thousands of Dollars)	Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Options Fair Value
NSP-Minnesota	2	\$ 325	\$ —	\$ —	\$ —	\$ 325

1 — Prices actively quoted or based on actively quoted prices.

2 — Prices based on models and other valuation methods.

Changes in the fair value of commodity trading contracts before the impacts of margin-sharing mechanisms for the years ended Dec. 31 were as follows:

(Thousands of Dollars)	2014	2013
Fair value of commodity trading net contract assets outstanding at Jan. 1	\$ 30,196	\$ 27,522
Contracts realized or settled during the period	(12,198)	(11,651)
Commodity trading contract additions and changes during the period	3,813	14,325
Fair value of commodity trading net contract assets outstanding at Dec. 31	<u>\$ 21,811</u>	<u>\$ 30,196</u>

At Dec. 31, 2014, a 10 percent increase in market prices for commodity trading contracts would increase pretax income by approximately \$0.9 million, whereas a 10 percent decrease would decrease pretax income by approximately \$0.9 million. At Dec. 31, 2013, a 10 percent increase in market prices for commodity trading contracts would decrease pretax income by approximately \$0.6 million, whereas a 10 percent decrease would increase pretax income by approximately \$0.6 million.

NSP-Minnesota's wholesale and commodity trading operations measure the outstanding risk exposure to price changes on transactions, contracts and obligations that have been entered into, but not closed, including transactions that are not recorded at fair value, using an industry standard methodology known as Value-at-Risk (VaR). VaR expresses the potential change in fair value on the outstanding transactions, contracts and obligations over a particular period of time under normal market conditions.

The VaRs for the NSP-Minnesota and PSCo commodity trading operations, calculated on a consolidated basis using a Monte Carlo simulation with a 95 percent confidence level and a one-day holding period, were as follows:

(Millions of Dollars)	Year Ended Dec. 31	VaR Limit	Average	High	Low
2014	\$ 0.57	\$ 3.00	\$ 0.61	\$ 4.06	\$ 0.13
2013	0.29	3.00	0.41	1.65	< 0.01

Interest Rate Risk — NSP-Minnesota is subject to the risk of fluctuating interest rates in the normal course of business. NSP-Minnesota's risk management policy allows interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate derivatives such as swaps, caps, collars and put or call options.

At Dec. 31, 2014 and 2013, a 100-basis-point change in the benchmark rate on NSP-Minnesota's variable rate debt would impact annual pretax interest expense by approximately \$1.4 million and \$1.7 million, respectively. See Note 9 to the consolidated financial statements for a discussion of NSP-Minnesota's interest rate derivatives.

NSP-Minnesota also maintains a nuclear decommissioning fund, as required by the NRC. The nuclear decommissioning fund is subject to interest rate risk and equity price risk. At Dec. 31, 2014, the fund was invested in a diversified portfolio of cash equivalents, debt securities, equity securities, and other investments. These investments may be used only for activities related to nuclear decommissioning. Given the purpose and legal restrictions on the use of nuclear decommissioning fund assets, realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund, including any other-than-temporary impairments, are deferred as a component of the regulatory asset for nuclear decommissioning. Since the accounting for nuclear decommissioning recognizes that costs are recovered through rates, fluctuations in equity prices or interest rates do not have a direct impact on earnings.

Credit Risk — NSP-Minnesota is also exposed to credit risk. Credit risk relates to the risk of loss resulting from counterparties' nonperformance on their contractual obligations. NSP-Minnesota maintains credit policies intended to minimize overall credit risk and actively monitors these policies to reflect changes and scope of operations.

At Dec. 31, 2014, a 10 percent increase in commodity prices would have resulted in a decrease in credit exposure of \$3.5 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of \$11.9 million. At Dec. 31, 2013, a 10 percent increase in commodity prices would have resulted in an increase in credit exposure of \$3.9 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of \$4.8 million.

NSP-Minnesota conducts standard credit reviews for all counterparties. NSP-Minnesota employs additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees, standardized master netting agreements and termination provisions that allow for offsetting of positive and negative exposures. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided. Distress in financial markets could increase NSP-Minnesota's credit risk.

Fair Value Measurements

NSP-Minnesota follows accounting and disclosure guidance on fair value measurements that contains a hierarchy for inputs used in measuring fair value and requires disclosure of the observability of the inputs used in these measurements. See Note 9 to the consolidated financial statements for further discussion of the fair value hierarchy and the amounts of assets and liabilities measured at fair value that have been assigned to Level 3.

Commodity Derivatives — NSP-Minnesota continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment and the typically short duration of these contracts, the impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at Dec. 31, 2014. NSP-Minnesota also assesses the impact of its own credit risk when determining the fair value of commodity derivative liabilities. The impact of discounting commodity derivative liabilities for credit risk was immaterial to the fair value of commodity derivative liabilities at Dec. 31, 2014.

Commodity derivative assets and liabilities assigned to Level 3 typically consist of FTRs, as well as forwards and options that are long-term in nature. Level 3 commodity derivative assets and liabilities represent 2.3 percent and 6.1 percent of gross assets and liabilities, respectively, measured at fair value at Dec. 31, 2014.

Determining the fair value of FTRs requires numerous management forecasts that vary in observability, including various forward commodity prices, retail and wholesale demand, generation and resulting transmission system congestion. Given the limited observability of management's forecasts for several of these inputs, these instruments have been assigned a Level 3. Level 3 commodity derivatives assets and liabilities included \$41.2 million and \$1.0 million of estimated fair values, respectively, for FTRs held at Dec. 31, 2014.

Determining the fair value of certain commodity forwards and options can require management to make use of subjective price and volatility forecasts which extend to periods beyond those readily observable on active exchanges or quoted by brokers. When less observable forward price and volatility forecasts are significant to determining the value of commodity forwards and options, these instruments are assigned to Level 3. There were no Level 3 forwards or options held at Dec. 31, 2014.

Nuclear Decommissioning Fund — Nuclear decommissioning fund assets assigned to Level 3 consist of private equity investments and real estate investments. Based on an evaluation of NSP-Minnesota's ability to redeem private equity investments and real estate investment funds measured at net asset value, estimated fair values for these investments totaling \$165.5 million in the nuclear decommissioning fund at Dec. 31, 2014 (approximately 9.3 percent of total assets measured at fair value) are assigned to Level 3. Realized and unrealized gains and losses on nuclear decommissioning fund investments are deferred as a regulatory asset.

Item 8 — Financial Statements and Supplementary Data

See Item 15-1 in Part IV for an index of financial statements included herein.

See Note 17 to the consolidated financial statements for summarized quarterly financial data.

Management Report on Internal Controls Over Financial Reporting

The management of NSP-Minnesota is responsible for establishing and maintaining adequate internal control over financial reporting. NSP-Minnesota's internal control system was designed to provide reasonable assurance to Xcel Energy Inc.'s and NSP-Minnesota's management and board of directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

NSP-Minnesota management assessed the effectiveness of NSP-Minnesota's internal control over financial reporting as of Dec. 31, 2014. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control — Integrated Framework (2013)*. Based on our assessment, we believe that, as of Dec. 31, 2014, NSP-Minnesota's internal control over financial reporting is effective at the reasonable assurance level based on those criteria.

/s/ BEN FOWKE

Ben Fowke
Chairman and Chief Executive Officer
Feb. 20, 2015

/s/ TERESA S. MADDEN

Teresa S. Madden
Executive Vice President, Chief Financial Officer
Feb. 20, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of
Northern States Power Company, a Minnesota corporation

We have audited the accompanying consolidated balance sheets and statements of capitalization of Northern States Power Company, a Minnesota corporation, and subsidiaries (the “Company”) as of December 31, 2014 and 2013, and the related consolidated statements of income, comprehensive income, cash flows, and common stockholder’s equity for each of the three years in the period ended December 31, 2014. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company’s management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Northern States Power Company, a Minnesota corporation, and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 20, 2015

NSP-MINNESOTA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(amounts in thousands)

	Year Ended Dec. 31		
	2014	2013	2012
Operating revenues			
Electric, non-affiliates	\$ 3,727,815	\$ 3,603,807	\$ 3,392,571
Electric, affiliates	474,542	458,633	449,958
Natural gas	757,695	591,017	471,765
Other	28,473	26,153	23,045
Total operating revenues	4,988,525	4,679,610	4,337,339
Operating expenses			
Electric fuel and purchased power	1,676,474	1,683,977	1,562,286
Cost of natural gas sold and transported	532,475	380,058	287,152
Cost of sales — other	17,371	16,154	13,505
Operating and maintenance expenses	1,223,829	1,171,855	1,102,302
Conservation program expenses	138,105	96,635	109,989
Depreciation and amortization	410,840	414,588	399,432
Taxes (other than income taxes)	221,838	206,741	204,387
Total operating expenses	4,220,932	3,970,008	3,679,053
Operating income	767,593	709,602	658,286
Other income (expense), net	580	(653)	979
Allowance for funds used during construction — equity	23,788	40,064	37,109
Interest charges and financing costs			
Interest charges — includes other financing costs of \$6,511, \$6,337 and \$5,972 respectively	199,667	191,889	201,158
Allowance for funds used during construction — debt	(10,711)	(18,079)	(20,449)
Total interest charges and financing costs	188,956	173,810	180,709
Income before income taxes	603,005	575,203	515,665
Income taxes	198,090	181,857	175,524
Net income	<u>\$ 404,915</u>	<u>\$ 393,346</u>	<u>\$ 340,141</u>

See Notes to Consolidated Financial Statements

NSP-MINNESOTA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(amounts in thousands)

	Year Ended Dec. 31		
	2014	2013	2012
Net income	\$ 404,915	\$ 393,346	\$ 340,141
Other comprehensive income (loss)			
Pension and retiree medical benefits:			
Net pension and retiree medical benefits gains arising during the period, net of tax of \$111, \$294 and \$315, respectively	161	423	460
Amortization of losses included in net periodic benefit cost, net of tax of \$16, \$63 and \$106, respectively	22	91	161
	183	514	621
Derivative instruments:			
Net fair value (decrease) increase, net of tax of \$(61), \$10 and \$(6,885), respectively	(89)	5	(9,889)
Reclassification of losses to net income, net of tax of \$568, \$560 and \$156, respectively	789	779	225
	700	784	(9,664)
Marketable securities:			
Net fair value increase, net of tax of \$22, \$120 and \$135, respectively	32	172	196
Other comprehensive income (loss)	915	1,470	(8,847)
Comprehensive income	\$ 405,830	\$ 394,816	\$ 331,294

See Notes to Consolidated Financial Statements

NSP-MINNESOTA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(amounts in thousands)

	Year Ended Dec. 31		
	2014	2013	2012
Operating activities			
Net income	\$ 404,915	\$ 393,346	\$ 340,141
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	416,380	419,852	404,325
Nuclear fuel amortization	114,542	98,089	102,651
Deferred income taxes	167,471	168,444	239,981
Amortization of investment tax credits	(1,735)	(1,813)	(2,700)
Allowance for equity funds used during construction	(23,788)	(40,064)	(37,109)
Provision for bad debts	17,193	13,418	11,241
Prairie Island extended power uprate	—	—	10,100
Net realized and unrealized hedging and derivative transactions	5,023	(4,175)	(53,881)
Changes in operating assets and liabilities:			
Accounts receivable	(104,655)	3,220	(214,886)
Accrued unbilled revenues	3,825	(25,748)	1,639
Inventories	(10,285)	(19,404)	41,090
Other current assets	(33,284)	22,316	(30,708)
Accounts payable	(50,569)	68,003	(29,055)
Net regulatory assets and liabilities	101,826	10,703	(15,416)
Other current liabilities	118,576	36,709	33,727
Pension and other employee benefit obligations	(41,924)	(59,953)	(71,149)
Change in other noncurrent assets	34,571	(9,599)	(14,465)
Change in other noncurrent liabilities	(5,985)	(4,463)	(552)
Net cash provided by operating activities	1,112,097	1,068,881	714,974
Investing activities			
Utility capital/construction expenditures	(1,241,940)	(1,548,952)	(1,172,403)
Allowance for equity funds used during construction	23,788	40,064	37,109
Proceeds from insurance recoveries	6,000	90,000	97,835
Purchases of investments in external decommissioning fund	(595,569)	(1,481,881)	(1,102,025)
Proceeds from the sale of investments in external decommissioning fund	588,430	1,461,291	1,087,076
Investments in utility money pool arrangement	(432,000)	(29,000)	—
Repayments from utility money pool arrangement	432,000	29,000	—
Change in restricted cash	—	—	95,287
Other, net	(3,066)	(3,716)	(3,507)
Net cash used in investing activities	(1,222,357)	(1,443,194)	(960,628)
Financing activities			
Proceeds from (repayments of) short-term borrowings, net	11,000	(90,000)	195,000
Borrowings under utility money pool arrangement	340,000	997,000	1,147,000
Repayments under utility money pool arrangement	(374,000)	(963,000)	(1,212,000)
Proceeds from issuance of long-term debt	295,337	394,788	786,363
Repayments of long-term debt, including reacquisition premiums	—	—	(648,874)
Capital contributions from parent	95,051	285,102	215,110
Dividends paid to parent	(259,451)	(235,499)	(234,108)
Net cash provided by financing activities	107,937	388,391	248,491
Net change in cash and cash equivalents	(2,323)	14,078	2,837
Cash and cash equivalents at beginning of period	42,920	28,842	26,005
Cash and cash equivalents at end of period	<u>\$ 40,597</u>	<u>\$ 42,920</u>	<u>\$ 28,842</u>
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	\$ (182,603)	\$ (166,515)	\$ (187,671)
Cash (paid) received for income taxes, net	(33,586)	2,064	(5,104)
Supplemental disclosure of non-cash investing transactions:			
Property, plant and equipment additions in accounts payable	\$ 186,068	\$ 234,686	\$ 125,948

See Notes to Consolidated Financial Statements

NSP-MINNESOTA AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(amounts in thousands, except share and per share data)

	Dec. 31	
	2014	2013
Assets		
Current assets		
Cash and cash equivalents	\$ 40,597	\$ 42,920
Accounts receivable, net	367,696	284,532
Accounts receivable from affiliates	24,067	19,769
Accrued unbilled revenues	251,587	255,412
Inventories	290,287	279,915
Regulatory assets	235,487	207,467
Derivative instruments	60,164	66,726
Deferred income taxes	76,016	80,095
Prepayments and other	142,443	118,036
Total current assets	<u>1,488,344</u>	<u>1,354,872</u>
Property, plant and equipment, net	11,661,620	10,589,522
Other assets		
Nuclear decommissioning fund and other investments	1,735,316	1,655,356
Regulatory assets	1,051,834	990,204
Derivative instruments	15,434	36,881
Other	34,768	68,060
Total other assets	<u>2,837,352</u>	<u>2,750,501</u>
Total assets	<u>\$ 15,987,316</u>	<u>\$ 14,694,895</u>
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	\$ 250,013	\$ 2
Short-term debt	142,000	131,000
Borrowings under utility money pool arrangement	—	34,000
Accounts payable	470,507	554,265
Accounts payable to affiliates	50,545	65,941
Regulatory liabilities	171,608	101,795
Taxes accrued	198,509	195,734
Accrued interest	61,339	59,846
Dividends payable to parent	77,802	58,752
Derivative instruments	12,294	13,066
Other	217,215	104,544
Total current liabilities	<u>1,651,832</u>	<u>1,318,945</u>
Deferred credits and other liabilities		
Deferred income taxes	2,429,143	2,253,915
Deferred investment tax credits	27,567	29,202
Regulatory liabilities	451,783	430,999
Asset retirement obligations	2,186,174	1,732,763
Derivative instruments	135,036	151,651
Pension and employee benefit obligations	340,774	307,282
Other	123,165	100,614
Total deferred credits and other liabilities	<u>5,693,642</u>	<u>5,006,426</u>
Commitments and contingencies		
Capitalization		
Long-term debt	3,938,669	3,888,730
Common stock — 5,000,000 shares authorized of \$0.01 par value; 1,000,000 shares outstanding at Dec. 31, 2014 and 2013, respectively	10	10
Additional paid in capital	2,961,654	2,866,603
Retained earnings	1,762,323	1,635,910
Accumulated other comprehensive loss	(20,814)	(21,729)
Total common stockholder's equity	<u>4,703,173</u>	<u>4,480,794</u>
Total liabilities and equity	<u>\$ 15,987,316</u>	<u>\$ 14,694,895</u>

See Notes to Consolidated Financial Statements

NSP-MINNESOTA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
(amounts in thousands, except share data)

	Common Stock			Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholder's Equity
	Shares	Par Value	Additional Paid In Capital			
Balance at Dec. 31, 2011	1,000,000	\$ 10	\$ 2,366,391	\$ 1,372,727	\$ (14,352)	\$ 3,724,776
Net income				340,141		340,141
Other comprehensive loss					(8,847)	(8,847)
Common dividends declared to parent				(234,811)		(234,811)
Contribution of capital by parent			215,110			215,110
Balance at Dec. 31, 2012	<u>1,000,000</u>	<u>\$ 10</u>	<u>\$ 2,581,501</u>	<u>\$ 1,478,057</u>	<u>\$ (23,199)</u>	<u>\$ 4,036,369</u>
Net income				393,346		393,346
Other comprehensive income					1,470	1,470
Common dividends declared to parent				(235,493)		(235,493)
Contribution of capital by parent			285,102			285,102
Balance at Dec. 31, 2013	<u>1,000,000</u>	<u>\$ 10</u>	<u>\$ 2,866,603</u>	<u>\$ 1,635,910</u>	<u>\$ (21,729)</u>	<u>\$ 4,480,794</u>
Net income				404,915		404,915
Other comprehensive income					915	915
Common dividends declared to parent				(278,502)		(278,502)
Contribution of capital by parent			95,051			95,051
Balance at Dec. 31, 2014	<u>1,000,000</u>	<u>\$ 10</u>	<u>\$ 2,961,654</u>	<u>\$ 1,762,323</u>	<u>\$ (20,814)</u>	<u>\$ 4,703,173</u>

See Notes to Consolidated Financial Statements

NSP-MINNESOTA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CAPITALIZATION
(amounts in thousands, except share and per share data)

	Dec. 31	
	2014	2013
Long-Term Debt		
First Mortgage Bonds, Series due:		
Aug. 15, 2015, 1.95%	\$ 250,000	\$ 250,000
March 1, 2018, 5.25%	500,000	500,000
Aug. 15, 2022, 2.15%	300,000	300,000
May 15, 2023, 2.6%	400,000	400,000
July 1, 2025, 7.125%	250,000	250,000
March 1, 2028, 6.5%	150,000	150,000
July 15, 2035, 5.25%	250,000	250,000
June 1, 2036, 6.25%	400,000	400,000
July 1, 2037, 6.2%	350,000	350,000
Nov. 1, 2039, 5.35%	300,000	300,000
Aug. 15, 2040, 4.85%	250,000	250,000
Aug. 15, 2042, 3.4%	500,000	500,000
May 15, 2044, 4.125%	300,000	—
Other	47	48
Unamortized discount	(11,365)	(11,316)
Total	4,188,682	3,888,732
Less current maturities	250,013	2
Total long-term debt	<u>\$ 3,938,669</u>	<u>\$ 3,888,730</u>
Common Stockholder's Equity		
Common stock — 5,000,000 shares authorized of \$0.01 par value; 1,000,000 shares outstanding at Dec. 31, 2014 and 2013, respectively	\$ 10	\$ 10
Additional paid in capital	2,961,654	2,866,603
Retained earnings	1,762,323	1,635,910
Accumulated other comprehensive loss	(20,814)	(21,729)
Total common stockholder's equity	<u>\$ 4,703,173</u>	<u>\$ 4,480,794</u>

See Notes to Consolidated Financial Statements

Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

Business and System of Accounts — NSP-Minnesota is engaged in the regulated generation, purchase, transmission, distribution and sale of electricity and in the regulated purchase, transportation, distribution and sale of natural gas. NSP-Minnesota’s consolidated financial statements and disclosures are presented in accordance with GAAP. All of NSP-Minnesota’s underlying accounting records also conform to the FERC uniform system of accounts or to systems required by various state regulatory commissions, which are the same in all material respects.

Principles of Consolidation — NSP-Minnesota’s consolidated financial statements include its wholly-owned subsidiaries. In the consolidation process, all intercompany transactions and balances are eliminated. NSP-Minnesota has investments in certain plants and transmission facilities jointly owned with nonaffiliated utilities. NSP-Minnesota’s proportionate share of jointly owned facilities is recorded as property, plant and equipment on the consolidated balance sheets and NSP-Minnesota’s proportionate share of the operating costs associated with these facilities is included in its consolidated statements of income. See Note 5 for further discussion of jointly owned generation and transmission facilities and related ownership percentages.

NSP-Minnesota evaluates its arrangements and contracts with other entities, including but not limited to, investments, PPAs and fuel contracts to determine if the other party is a variable interest entity, if NSP-Minnesota has a variable interest and if NSP-Minnesota is the primary beneficiary. NSP-Minnesota follows accounting guidance for variable interest entities which requires consideration of the activities that most significantly impact an entity’s financial performance and power to direct those activities, when determining whether NSP-Minnesota is a variable interest entity’s primary beneficiary. See Note 11 for further discussion of variable interest entities.

Use of Estimates — In recording transactions and balances resulting from business operations, NSP-Minnesota uses estimates based on the best information available. Estimates are used for such items as plant depreciable lives or potential disallowances, AROs, certain regulatory assets and liabilities, tax provisions, uncollectible amounts, environmental costs, unbilled revenues, jurisdictional fuel and energy cost allocations and actuarially determined benefit costs. The recorded estimates are revised when better information becomes available or when actual amounts can be determined. Those revisions can affect operating results.

Regulatory Accounting — NSP-Minnesota accounts for certain income and expense items in accordance with accounting guidance for regulated operations. Under this guidance:

- Certain costs, which would otherwise be charged to expense or OCI, are deferred as regulatory assets based on the expected ability to recover the costs in future rates; and
- Certain credits, which would otherwise be reflected as income, are deferred as regulatory liabilities based on the expectation the amounts will be returned to customers in future rates, or because the amounts were collected in rates prior to the costs being incurred.

Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with the treatment in the rate setting process.

If restructuring or other changes in the regulatory environment occur, NSP-Minnesota may no longer be eligible to apply this accounting treatment, and may be required to eliminate regulatory assets and liabilities from its balance sheet. Such changes could have a material effect on NSP-Minnesota’s financial condition, results of operations and cash flows. See Note 13 for further discussion of regulatory assets and liabilities.

Revenue Recognition — Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers is based on the reading of their meter, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is recognized. NSP-Minnesota presents its revenues net of any excise or other fiduciary-type taxes or fees.

NSP-Minnesota participates in MISO. The revenues and charges from MISO related to serving retail and wholesale electric customers comprising the native load of NSP-Minnesota are recorded on a net basis within cost of sales. Revenues and charges for short term wholesale sales of excess energy transacted through MISO are recorded on a gross basis in electric revenues and cost of sales.

NSP-Minnesota has various rate-adjustment mechanisms in place that provide for the recovery of natural gas, electric fuel and purchased energy costs. These cost-adjustment tariffs may increase or decrease the level of revenue collected from customers and are revised periodically for differences between the total amount collected under the clauses and the costs incurred. When applicable, under governing regulatory commission rate orders, fuel cost over-recoveries (the excess of fuel revenue billed to customers over fuel costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as regulatory assets.

Conservation Programs — NSP-Minnesota has implemented programs in its retail jurisdictions to assist customers in conserving energy and reducing peak demand on the electric and natural gas systems. These programs include commercial process efficiency and lighting upgrades, as well as residential rebates for participation in air conditioning interruption and energy-efficient appliances.

The costs incurred for CIP programs are deferred if it is probable future revenue will be provided to permit recovery of the incurred cost. Recorded revenues for incentive programs designed for recovery of lost margins and/or conservation performance incentives are limited to amounts expected to be collected within 24 months from the annual period in which they are earned.

NSP-Minnesota's CIP program costs are recovered through a combination of base rate revenue and rider mechanisms. The revenue billed to customers recovers incurred costs for conservation programs and also incentive amounts that are designed to encourage NSP-Minnesota's achievement of energy conservation goals and to compensate for related lost sales margin. NSP-Minnesota recognizes regulatory assets to reflect the amount of costs or earned incentives that have not yet been collected from customers.

Property, Plant and Equipment and Depreciation — Property, plant and equipment is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and AFUDC. The cost of plant retired is charged to accumulated depreciation and amortization. Amounts recovered in rates for future removal costs are recorded as regulatory liabilities. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance costs are charged to expense as incurred. Maintenance and replacement of items determined to be less than a unit of property are charged to operating expenses as incurred. Planned major maintenance activities are charged to operating expense unless the cost represents the acquisition of an additional unit of property or the replacement of an existing unit of property. Property, plant and equipment also includes costs associated with property held for future use. The depreciable lives of certain plant assets are reviewed annually and revised, if appropriate. Property, plant and equipment that is required to be decommissioned early by a regulator is reclassified as plant to be retired.

Property, plant and equipment is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. A loss is recognized in the current period if it becomes probable that part of a cost of a plant under construction or recently completed plant will be disallowed for recovery from customers and a reasonable estimate of the disallowance can be made. For investments in property, plant and equipment that are abandoned and not expected to go into service, incurred costs and related deferred tax amounts are compared to the discounted estimated future rate recovery, and a loss is recognized, if necessary.

NSP-Minnesota records depreciation expense related to its plant using the straight-line method over the plant's useful life. Actuarial life studies are performed and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 2.5, 2.9 and 2.9 percent for the years ended Dec. 31, 2014, 2013 and 2012, respectively.

Leases — NSP-Minnesota evaluates a variety of contracts for lease classification at inception, including PPAs and rental arrangements for office space, vehicles, and equipment. Contracts determined to contain a lease because of per unit pricing that is other than fixed or market price, terms regarding the use of a particular asset, and other factors are evaluated further to determine if the arrangement is a capital lease. See Note 11 for further discussion of leases.

AFUDC — AFUDC represents the cost of capital used to finance utility construction activity. AFUDC is computed by applying a composite financing rate to qualified CWIP. The amount of AFUDC capitalized as a utility construction cost is credited to nonoperating income (for equity capital) and interest charges (for debt capital). AFUDC amounts capitalized are included in NSP-Minnesota's rate base for establishing utility service rates. In addition to construction-related amounts, cost of capital also is recorded to reflect returns on capital used to finance conservation programs in Minnesota.

Generally AFUDC costs are recovered from customers as the related property is depreciated. However, in some cases, including certain wind and transmission projects, the MPUC has approved a more current recovery of the cost of capital associated with large capital projects, through various riders, resulting in a lower recognition of AFUDC.

AROs — NSP-Minnesota accounts for AROs under accounting guidance that requires a liability for the fair value of an ARO to be recognized in the period in which it is incurred if it can be reasonably estimated, with the offsetting associated asset retirement costs capitalized as a long-lived asset. The liability is generally increased over time by applying the effective interest method of accretion, and the capitalized costs are depreciated over the useful life of the long-lived asset. Changes resulting from revisions to the timing or amount of expected asset retirement cash flows are recognized as an increase or a decrease in the ARO. NSP-Minnesota also recovers through rates certain future plant removal costs in addition to AROs. The accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability. See Note 11 for further discussion of AROs.

Nuclear Decommissioning — Nuclear decommissioning studies estimate NSP-Minnesota's ultimate costs of decommissioning its nuclear power plants and are performed at least every three years and submitted to the MPUC and other state commissions for approval. NSP-Minnesota filed its most recent triennial nuclear decommissioning studies with the MPUC in December 2014. These studies reflect NSP-Minnesota's plans, under the current operating licenses, for prompt dismantlement of the Monticello and PI facilities. These studies assume that NSP-Minnesota will store spent fuel on site pending removal to a U.S. government facility.

For rate making purposes, NSP-Minnesota recovers the total decommissioning costs related to its nuclear power plants over each facility's expected service life based on the triennial decommissioning studies filed with the MPUC and other state commissions. The studies consider estimated future costs of decommissioning and the market value of investments in trust funds, and recommend annual funding amounts. Amounts collected in rates are deposited in the trust funds. See Note 12 for further discussion of the approved nuclear decommissioning studies and funded amounts. For financial reporting purposes, NSP-Minnesota accounts for nuclear decommissioning as an ARO as described above.

Restricted funds for the payment of future decommissioning expenditures for NSP-Minnesota's nuclear facilities are included in the nuclear decommissioning fund on the consolidated balance sheets. See Note 9 for further discussion of the nuclear decommissioning fund.

Nuclear Fuel Expense — Nuclear fuel expense, which is recorded as NSP-Minnesota's nuclear generating plants use fuel, includes the cost of fuel used in the current period (including AFUDC), as well as future disposal costs of spent nuclear fuel and costs associated with the end-of-life fuel segments.

Nuclear Refueling Outage Costs — NSP-Minnesota uses a deferral and amortization method for nuclear refueling O&M costs. This method amortizes refueling outage costs over the period between refueling outages consistent with how the costs are recovered ratably in electric rates.

Income Taxes — NSP-Minnesota accounts for income taxes using the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. NSP-Minnesota defers income taxes for all temporary differences between pretax financial and taxable income, and between the book and tax bases of assets and liabilities. NSP-Minnesota uses the tax rates that are scheduled to be in effect when the temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date.

Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized. In making such a determination, all available evidence is considered, including scheduled reversals of deferred tax liabilities, projected future taxable income, tax planning strategies and recent financial operations.

Due to the effects of past regulatory practices, when deferred taxes were not required to be recorded due to the use of flow through accounting for ratemaking purposes, the reversal of some temporary differences are accounted for as current income tax expense. Investment tax credits are deferred and their benefits amortized over the book depreciable lives of the related property. Utility rate regulation also has resulted in the recognition of certain regulatory assets and liabilities related to income taxes, which are summarized in Note 13.

NSP-Minnesota follows the applicable accounting guidance to measure and disclose uncertain tax positions that it has taken or expects to take in its income tax returns. NSP-Minnesota recognizes a tax position in its consolidated financial statements when it is more likely than not that the position will be sustained upon examination based on the technical merits of the position. Recognition of changes in uncertain tax positions are reflected as a component of income tax.

NSP-Minnesota reports interest and penalties related to income taxes within the other income and interest charges sections in the consolidated statements of income.

Xcel Energy Inc. and its subsidiaries, including NSP-Minnesota, file consolidated federal income tax returns as well as combined or separate state income tax returns. Federal income taxes paid by Xcel Energy Inc. are allocated to Xcel Energy Inc.'s subsidiaries based on separate company computations of tax. A similar allocation is made for state income taxes paid by Xcel Energy Inc. in connection with combined state filings. Xcel Energy Inc. also allocates its own income tax benefits to its direct subsidiaries which are recorded directly in equity by the subsidiaries based on the relative positive tax liabilities of the subsidiaries.

See Note 6 for further discussion of income taxes.

Types of and Accounting for Derivative Instruments — NSP-Minnesota uses derivative instruments in connection with its interest rate, utility commodity price, vehicle fuel price, and commodity trading activities, including forward contracts, futures, swaps and options. All derivative instruments not designated and qualifying for the normal purchases and normal sales exception, as defined by the accounting guidance for derivatives and hedging, are recorded on the consolidated balance sheets at fair value as derivative instruments. This includes certain instruments used to mitigate market risk for the utility operations including transmission in organized markets and all instruments related to the commodity trading operations. The classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship. Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms.

Gains or losses on commodity trading transactions are recorded as a component of electric operating revenues; hedging transactions for vehicle fuel costs are recorded as a component of capital projects or O&M costs; and interest rate hedging transactions are recorded as a component of interest expense. NSP-Minnesota is allowed to recover in electric or natural gas rates the costs of certain financial instruments purchased to reduce commodity cost volatility. For further information on derivatives entered to mitigate commodity price risk on behalf of electric and natural gas customers, see Note 9.

Cash Flow Hedges — Certain qualifying hedging relationships are designated as a hedge of a forecasted transaction or future cash flow (cash flow hedge). Changes in the fair value of a derivative designated as a cash flow hedge, to the extent effective are included in OCI, or deferred as a regulatory asset or liability based on recovery mechanisms until earnings are affected by the hedged transaction.

Normal Purchases and Normal Sales — NSP-Minnesota enters into contracts for the purchase and sale of commodities for use in its business operations. Derivatives and hedging accounting guidance requires a company to evaluate these contracts to determine whether the contracts are derivatives. Certain contracts that meet the definition of a derivative may be exempted from derivative accounting if designated as normal purchases or normal sales.

NSP-Minnesota evaluates all of its contracts at inception to determine if they are derivatives and if they meet the normal purchases and normal sales designation requirements. None of the contracts entered into within the commodity trading operations qualify for a normal purchases and normal sales designation.

See Note 9 for further discussion of NSP-Minnesota's risk management and derivative activities.

Commodity Trading Operations — All applicable gains and losses related to commodity trading activities, whether or not settled physically, are shown on a net basis in electric operating revenues in the consolidated statements of income.

Pursuant to the JOA approved by the FERC, some of NSP-Minnesota's commodity trading margins are apportioned to PSCo and SPS. Commodity trading activities are not associated with energy produced from NSP-Minnesota's generation assets or energy and capacity purchased to serve native load. Commodity trading contracts are recorded at fair market value and commodity trading results include the impact of all margin-sharing mechanisms. For further information, see Note 9.

Fair Value Measurements — NSP-Minnesota presents cash equivalents, interest rate derivatives, commodity derivatives and nuclear decommissioning fund assets at estimated fair values in its consolidated financial statements. Cash equivalents are recorded at cost plus accrued interest; money market funds are measured using quoted net asset values. For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used as a primary input to establish fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price for an identical contract in an active market, NSP-Minnesota may use quoted prices for similar contracts or internally prepared valuation models to determine fair value. For the nuclear decommissioning fund, published trading data and pricing models, generally using the most observable inputs available, are utilized to estimate fair value for each security. For further information, see Note 9.

Cash and Cash Equivalents — NSP-Minnesota considers investments in certain instruments, including commercial paper and money market funds, with a remaining maturity of 3 months or less at the time of purchase, to be cash equivalents.

Accounts Receivable and Allowance for Bad Debts — Accounts receivable are stated at the actual billed amount net of an allowance for bad debts. NSP-Minnesota establishes an allowance for uncollectible receivables based on a policy that reflects its expected exposure to the credit risk of customers.

Inventory — All inventory is recorded at average cost.

RECs — 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. RECs are typically used as a form of measurement of compliance to RPS enacted by those states that are encouraging construction and consumption from renewable energy sources, but can also be sold separately from the energy produced. NSP-Minnesota acquires RECs from the generation or purchase of renewable power.

When RECs are purchased or acquired in the course of generation they are recorded as inventory at cost. The cost of RECs that are utilized for compliance purposes is recorded as electric fuel and purchased power expense.

Sales of RECs that are purchased or acquired in the course of generation are recorded in electric utility operating revenues on a gross basis. The cost of these RECs, related transaction costs, and amounts credited to customers under margin-sharing mechanisms are recorded in electric fuel and purchased power expense. The sales of RECs for trading purposes are recorded in electric utility operating revenues, net of the cost of the RECs, transaction costs, and amounts credited to customers under margin-sharing mechanisms.

Emission Allowances — Emission allowances, including the annual SO₂ and NO_x emission allowance entitlement received from the EPA, are recorded at cost plus associated broker commission fees. NSP-Minnesota follows the inventory accounting model for all emission allowances. Sales of emission allowances are included in electric utility operating revenues and the operating activities section of the consolidated statements of cash flows.

Environmental Costs — Environmental costs are recorded when it is probable NSP-Minnesota is liable for remediation costs and the liability can be reasonably estimated. Costs are deferred as a regulatory asset if it is probable that the costs will be recovered from customers in future rates. Otherwise, the costs are expensed. If an environmental expense is related to facilities currently in use, such as emission-control equipment, the cost is capitalized and depreciated over the life of the plant.

Estimated remediation costs, excluding inflationary increases, are recorded. The estimates are based on experience, an assessment of the current situation and the technology currently available for use in the remediation. The recorded costs are regularly adjusted as estimates are revised and remediation proceeds. If other participating PRPs exist and acknowledge their potential involvement with a site, costs are estimated and recorded only for NSP-Minnesota's expected share of the cost. Any future costs of restoring sites where operation may extend indefinitely are treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for removal expenses, which may include final remediation costs. Removal costs recovered in rates before the related costs are incurred are classified as a regulatory liability.

See Note 11 for further discussion of environmental costs.

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

Based on regulatory recovery mechanisms, certain unrecognized actuarial gains and losses and unrecognized prior service costs or credits are recorded as regulatory assets and liabilities, rather than OCI.

See Note 7 for further discussion of benefit plans and other postretirement benefits.

Guarantees — NSP-Minnesota recognizes, upon issuance or modification of a guarantee, a liability for the fair market value of the obligation that has been assumed in issuing the guarantee. This liability includes consideration of specific triggering events and other conditions which may modify the ongoing obligation to perform under the guarantee.

The obligation recognized is reduced over the term of the guarantee as NSP-Minnesota is released from risk under the guarantee. See Note 11 for specific details of issued guarantees.

Subsequent Events — Management has evaluated the impact of events occurring after Dec. 31, 2014 up to the date of issuance of these consolidated financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation.

2. Accounting Pronouncements

Recently Issued

Revenue Recognition — In May 2014, the FASB issued *Revenue from Contracts with Customers, Topic 606 (ASU No. 2014-09)*, which provides a framework for the recognition of revenue, with the objective that recognized revenues properly reflect amounts an entity is entitled to receive in exchange for goods and services. This guidance, which includes additional disclosure requirements regarding revenue, cash flows and obligations related to contracts with customers, will be effective for interim and annual reporting periods beginning after Dec. 15, 2016. NSP-Minnesota is currently evaluating the impact of adopting ASU 2014-09 on its consolidated financial statements.

3. Selected Balance Sheet Data

(Thousands of Dollars)	Dec. 31, 2014	Dec. 31, 2013
Accounts receivable, net		
Accounts receivable	\$ 390,633	\$ 304,748
Less allowance for bad debts	(22,937)	(20,216)
	<u>\$ 367,696</u>	<u>\$ 284,532</u>
Inventories		
Materials and supplies	\$ 157,376	\$ 144,140
Fuel	77,139	81,971
Natural gas	55,772	53,804
	<u>\$ 290,287</u>	<u>\$ 279,915</u>

(Thousands of Dollars)	Dec. 31, 2014	Dec. 31, 2013
Property, plant and equipment, net		
Electric plant	\$ 14,831,286	\$ 13,530,767
Natural gas plant	1,177,021	1,092,314
Common and other property	568,287	503,168
CWIP	706,979	902,820
Total property, plant and equipment	17,283,573	16,029,069
Less accumulated depreciation	(6,012,145)	(5,783,658)
Nuclear fuel	2,347,422	2,186,799
Less accumulated amortization	(1,957,230)	(1,842,688)
	<u>\$ 11,661,620</u>	<u>\$ 10,589,522</u>

4. Borrowings and Other Financing Instruments

Short-Term Borrowings

Money Pool — Xcel Energy Inc. and its utility subsidiaries have established a money pool arrangement that allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc. Money pool borrowings for NSP-Minnesota were as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2014
Borrowing limit	\$ 250
Amount outstanding at period end	—
Average amount outstanding	—
Maximum amount outstanding	5
Weighted average interest rate, computed on a daily basis	0.27%
Weighted average interest rate at period end	N/A

(Amounts in Millions, Except Interest Rates)	Twelve Months Ended Dec. 31, 2014	Twelve Months Ended Dec. 31, 2013	Twelve Months Ended Dec. 31, 2012
Borrowing limit	\$ 250	\$ 250	\$ 250
Amount outstanding at period end	—	34	—
Average amount outstanding	12	42	56
Maximum amount outstanding	150	211	236
Weighted average interest rate, computed on a daily basis	0.21%	0.30%	0.33%
Weighted average interest rate at period end	N/A	0.25	N/A

Commercial Paper — NSP-Minnesota meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility. Commercial paper outstanding for NSP-Minnesota was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2014
Borrowing limit	\$ 500
Amount outstanding at period end	142
Average amount outstanding	61
Maximum amount outstanding	146
Weighted average interest rate, computed on a daily basis	0.34%
Weighted average interest rate at period end	0.53

(Amounts in Millions, Except Interest Rates)	Twelve Months Ended Dec. 31, 2014	Twelve Months Ended Dec. 31, 2013	Twelve Months Ended Dec. 31, 2012
Borrowing limit	\$ 500	\$ 500	\$ 500
Amount outstanding at period end	142	131	221
Average amount outstanding	111	97	59
Maximum amount outstanding	397	347	302
Weighted average interest rate, computed on a daily basis	0.26%	0.34%	0.39%
Weighted average interest rate at end of period	0.53	0.25	0.39

Letters of Credit — NSP-Minnesota uses letters of credit, generally with terms of one-year, to provide financial guarantees for certain operating obligations. At Dec. 31, 2014 and 2013, there were \$24.1 million and \$15.9 million of letters of credit outstanding, respectively, under the credit facility. The contract amounts of these letters of credit approximate their fair value and are subject to fees.

Credit Facility — In order to use its commercial paper program to fulfill short-term funding needs, NSP-Minnesota must have a revolving credit facility in place at least equal to the amount of its commercial paper borrowing limit and cannot issue commercial paper in an amount exceeding available capacity under this credit facility. The line of credit provides short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

Amended Credit Agreement — In October 2014, NSP-Minnesota entered into an amended five-year credit agreement with a syndicate of banks. The amended credit agreement has substantially the same terms and conditions as the prior credit agreement with an extension of maturity from July 2017 to October 2019. The borrowing limit for NSP-Minnesota remained at \$500 million.

NSP-Minnesota has the right to request an extension of the revolving termination date for two additional one-year periods. All extension requests are subject to majority bank group approval.

Other features of NSP-Minnesota's credit facility include:

- NSP-Minnesota may increase its credit facility by up to \$100 million.
- The credit facility has a financial covenant requiring that the debt-to-total capitalization ratio be less than or equal to 65 percent. NSP-Minnesota was in compliance as its debt-to-total capitalization ratio was 48 percent and 47 percent at Dec. 31, 2014 and 2013, respectively. If NSP-Minnesota does not comply with the covenant, an event of default may be declared, and if not remedied, any outstanding amounts due under the facility can be declared due by the lender.
- The credit facility has a cross-default provision that provides NSP-Minnesota will be in default on its borrowings under the facility if NSP-Minnesota or any of its subsidiaries whose total assets exceed 15 percent of NSP-Minnesota's consolidated total assets, default on certain indebtedness in an aggregate principal amount exceeding \$75 million.
- The interest rates under the line of credit are based on Eurodollar borrowing margins ranging from 87.5 to 175 basis points per year based on the applicable long-term credit ratings.
- The commitment fees, also based on applicable long-term credit ratings, are calculated on the unused portion of the lines of credit at a range of 7.5 to 27.5 basis points per year.

At Dec. 31, 2014, NSP-Minnesota had the following committed credit facility available (in millions):

Credit Facility ^(a)	Drawn ^(b)	Available
\$ 500.0	\$ 166.1	\$ 333.9

(a) These credit facilities have been amended to extend the maturity to October 2019.

(b) Includes outstanding commercial paper and letters of credit.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the credit facility. NSP-Minnesota had no direct advances on the credit facility outstanding at Dec. 31, 2014 and 2013.

Long-Term Borrowings and Other Financing Instruments

Generally, all real and personal property of NSP-Minnesota is subject to the lien of its first mortgage indenture. Debt premiums, discounts and expenses are amortized over the life of the related debt. The premiums, discounts and expenses associated with refinanced debt are deferred and amortized over the life of the related new issuance, in accordance with regulatory guidelines.

In May 2014, NSP-Minnesota issued \$300 million of 4.125 percent first mortgage bonds due May 15, 2044. In May 2013, NSP-Minnesota issued \$400 million of 2.60 percent first mortgage bonds due May 15, 2023.

During the next five years, NSP-Minnesota has long-term debt maturities of \$250 million and \$500 million due in 2015 and 2018, respectively.

Deferred Financing Costs — Other assets included deferred financing costs of approximately \$33.6 million and \$32.6 million, net of amortization, at Dec. 31, 2014 and 2013, respectively. NSP-Minnesota is amortizing these financing costs over the remaining maturity periods of the related debt.

Dividend and Other Capital-Restrictions — NSP-Minnesota's dividends are subject to the FERC's jurisdiction under the Federal Power Act, which prohibits the payment of dividends out of capital accounts; payment of dividends is allowed out of retained earnings only.

NSP-Minnesota's first mortgage indenture places certain restrictions on the amount of cash dividends it can pay to Xcel Energy Inc., the holder of its common stock. Even with this restriction, NSP-Minnesota could have paid more than \$1.6 billion and \$1.4 billion in additional cash dividends on common stock at Dec. 31, 2014 and 2013, respectively.

The most restrictive dividend limitation for NSP-Minnesota is imposed by its state regulatory commissions. NSP-Minnesota's state regulatory commissions indirectly limit the amount of dividends NSP-Minnesota can pay to Xcel Energy Inc. by requiring an equity-to-total capitalization ratio between 47.1 percent and 57.5 percent. NSP-Minnesota's equity-to-total capitalization ratio was 52.1 percent at Dec. 31, 2014 and \$848 million in retained earnings was not restricted. Total capitalization for NSP-Minnesota was \$9.0 billion at Dec. 31, 2014, which did not exceed the limits imposed by the commissions of \$9.5 billion.

5. Joint Ownership of Generation and Transmission Facilities

Following are the investments by NSP-Minnesota in jointly owned generation and transmission facilities and the related ownership percentages as of Dec. 31, 2014:

(Thousands of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Ownership %
Electric Generation:				
Sherco Unit 3	\$ 591,027	\$ 376,322	\$ 4,508	59.0%
Sherco Common Facilities Units 1, 2 and 3	144,799	90,022	2	80.0
Sherco Substation	4,790	2,978	—	59.0
Electric Transmission:				
Grand Meadow Line and Substation	10,647	1,452	—	50.0
CapX2020	775,365	89,567	259,294	50.9
Total	<u>\$ 1,526,628</u>	<u>\$ 560,341</u>	<u>\$ 263,804</u>	

NSP-Minnesota has approximately 500 MW of jointly owned generating capacity. NSP-Minnesota's share of operating expenses and construction expenditures are included in the applicable utility accounts. Each of the respective owners is responsible for providing its own financing.

6. Income Taxes

Tax Increase Prevention Act of 2014 — In 2014, the Tax Increase Prevention Act (TIPA) was signed into law. The TIPA provides for the following:

- The R&E credit was extended for 2014;

- PTCs were extended for projects that began construction before the end of 2014 with certain projects qualifying into future years; and
- 50 percent bonus depreciation was extended one year through 2014. Additionally, some longer production period property placed in service in 2015 is also eligible for 50 percent bonus depreciation.

The accounting related to the TIPA was recorded beginning in the fourth quarter of 2014 because a change in tax law is accounted for in the period of enactment.

American Taxpayer Relief Act of 2012 — In 2013, the American Taxpayer Relief Act (ATRA) was signed into law. The ATRA provided for the following:

- The top tax rate for dividends increased from 15 percent to 20 percent. The 20 percent dividend rate is now consistent with the tax rates for capital gains;
- The R&E credit was extended for 2012 and 2013;
- PTCs were extended for projects that began construction before the end of 2013 with certain projects qualifying into future years; and
- 50 percent bonus depreciation was extended one year through 2013. Additionally, some longer production period property placed in service in 2014 is also eligible for 50 percent bonus depreciation.

The accounting related to the ATRA, including the provisions related to 2012, was recorded beginning in the first quarter of 2013 because a change in tax law is accounted for in the period of enactment.

Federal Tax Loss Carryback Claims — In 2012, 2013 and 2014, NSP-Minnesota identified certain expenses related to 2009, 2010, 2011, 2013 and 2014 that qualify for an extended carryback beyond the typical two-year carryback period. As a result of a higher tax rate in prior years, NSP-Minnesota recognized a tax benefit of approximately \$17 million in 2014, \$12 million in 2013 and \$15 million in 2012.

Federal Audit — NSP-Minnesota is a member of the Xcel Energy affiliated group that files a consolidated federal income tax return. The statute of limitations applicable to Xcel Energy's 2008 federal income tax return expired in September 2012. The statute of limitations applicable to Xcel Energy's 2009 federal income tax return expires in March 2016. In the third quarter of 2012, the IRS commenced an examination of tax years 2010 and 2011, including the 2009 carryback claim. As of Dec. 31, 2014, the IRS had proposed an adjustment to the federal tax loss carryback claims that would result in \$12 million of income tax expense for the 2009 through 2011 claims, the recently filed 2013 claim, and the anticipated claim for 2014. At Dec. 31, 2014, the IRS has begun the Appeals process; however, the outcome and timing of a resolution is uncertain.

State Audits — NSP-Minnesota is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of Dec. 31, 2014, NSP-Minnesota's earliest open tax year that is subject to examination by state taxing authorities under applicable statutes of limitations is 2009. There are currently no state income tax audits in progress.

Unrecognized Tax Benefits — The unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the annual ETR. In addition, the unrecognized tax benefit balance includes temporary tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the ETR but would accelerate the payment of cash to the taxing authority to an earlier period.

A reconciliation of the amount of unrecognized tax benefit is as follows:

(Millions of Dollars)	Dec. 31, 2014	Dec. 31, 2013
Unrecognized tax benefit — Permanent tax positions	\$ 12.2	\$ 8.5
Unrecognized tax benefit — Temporary tax positions	18.2	16.7
Total unrecognized tax benefit	<u>\$ 30.4</u>	<u>\$ 25.2</u>

A reconciliation of the beginning and ending amount of unrecognized tax benefit is as follows:

(Millions of Dollars)	2014	2013	2012
Balance at Jan. 1	\$ 25.2	\$ 19.5	\$ 16.7
Additions based on tax positions related to the current year	10.3	8.1	1.7
Reductions based on tax positions related to the current year	(1.2)	—	(2.2)
Additions for tax positions of prior years	8.9	11.6	6.4
Reductions for tax positions of prior years	(4.2)	(1.9)	(3.1)
Settlements with taxing authorities	(8.6)	(12.1)	—
Balance at Dec. 31	<u>\$ 30.4</u>	<u>\$ 25.2</u>	<u>\$ 19.5</u>

The unrecognized tax benefit amounts were reduced by the tax benefits associated with NOL and tax credit carryforwards. The amounts of tax benefits associated with NOL and tax credit carryforwards are as follows:

(Millions of Dollars)	Dec. 31, 2014	Dec. 31, 2013
NOL and tax credit carryforwards	\$ (10.8)	\$ (12.4)

It is reasonably possible that NSP-Minnesota's amount of unrecognized tax benefits could significantly change in the next 12 months as the IRS Appeals process progresses and state audits resume. As the IRS Appeals process moves closer to completion, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately \$4 million.

The payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards. The payables for interest related to unrecognized tax benefits at Dec. 31, 2014, 2013 and 2012 were not material. No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2014, 2013 or 2012.

Other Income Tax Matters — NOL amounts represent the amount of the tax loss that is carried forward and tax credits represent the deferred tax asset. NOL and tax credit carryforwards as of Dec. 31 were as follows:

(Millions of Dollars)	2014	2013
Federal NOL carryforward	\$ 598.3	\$ 593.8
Federal tax credit carryforwards	136.6	107.0
State NOL carryforwards	43.7	—
State tax credit carryforwards, net of federal detriment	2.8	2.4

The federal carryforward periods expire between 2021 and 2034. The state carryforward periods expire between 2017 and 2033.

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

	2014	2013	2012
Federal statutory rate	35.0%	35.0%	35.0%
Increases (decreases) in tax from:			
Tax credits recognized, net of federal income tax expense	(5.3)	(5.3)	(4.6)
NOL carryback	(2.3)	(2.0)	(2.9)
Regulatory differences — utility plant items	(0.2)	(1.8)	(1.6)
State income taxes, net of federal income tax benefit	5.8	5.6	8.5
Change in unrecognized tax benefits	0.6	1.0	(0.1)
Other, net	(0.7)	(0.9)	(0.3)
Effective income tax rate	<u>32.9%</u>	<u>31.6%</u>	<u>34.0%</u>

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

(Thousands of Dollars)	2014	2013	2012
Current federal tax (benefit) expense	\$ (124)	\$ (6,181)	\$ (85,347)
Current state tax expense	25,650	11,197	19,593
Current change in unrecognized tax expense	6,828	10,210	3,997
Deferred federal tax expense	143,295	135,539	196,655
Deferred state tax expense	27,256	37,381	47,869
Deferred change in unrecognized tax (benefit)	(3,080)	(4,476)	(4,543)
Deferred investment tax credits	(1,735)	(1,813)	(2,700)
Total income tax expense	<u>\$ 198,090</u>	<u>\$ 181,857</u>	<u>\$ 175,524</u>

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

(Thousands of Dollars)	2014	2013	2012
Deferred tax expense excluding items below	\$ 184,544	\$ 210,856	\$ 285,726
Tax (expense) benefit allocated to other comprehensive income and other	(656)	(1,046)	6,172
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(16,417)	(41,366)	(51,917)
Deferred tax expense	<u>\$ 167,471</u>	<u>\$ 168,444</u>	<u>\$ 239,981</u>

The components of the net deferred tax liability (current and noncurrent) at Dec. 31 were as follows:

(Thousands of Dollars)	2014	2013
Deferred tax liabilities:		
Differences between book and tax bases of property	\$ 2,628,577	\$ 2,371,864
Regulatory assets	134,550	169,411
Employee benefits	7,066	—
Other	32,663	27,720
Total deferred tax liabilities	<u>\$ 2,802,856</u>	<u>\$ 2,568,995</u>
Deferred tax assets:		
NOL carryforward	\$ 217,323	\$ 209,353
Tax credit carryforward	139,474	109,495
Rate Refund	30,785	—
Regulatory liabilities	16,585	16,232
Deferred investment tax credits	12,200	12,951
Employee benefits	—	16,232
Bad debts	—	8,259
Other	28,126	22,654
Total deferred tax assets	<u>\$ 444,493</u>	<u>\$ 395,176</u>
Net deferred tax liability	<u>\$ 2,358,363</u>	<u>\$ 2,173,819</u>

7. Benefit Plans and Other Postretirement Benefits

Consistent with the process for rate recovery of pension and postretirement benefits for its employees, NSP-Minnesota accounts for its participation in, and related costs of, pension and other postretirement benefit plans sponsored by Xcel Energy Inc. as multiple employer plans. NSP-Minnesota is responsible for its share of cash contributions, plan costs and obligations and is entitled to its share of plan assets; accordingly, NSP-Minnesota accounts for its pro rata share of these plans, including pension expense and contributions, resulting in accounting consistent with that of a single employer plan exclusively for NSP-Minnesota employees.

Xcel Energy, which includes NSP-Minnesota, offers various benefit plans to its employees. Approximately 60 percent of employees that receive benefits are represented by several local labor unions under several collective-bargaining agreements. At Dec. 31, 2014, NSP-Minnesota had 2,011 bargaining employees covered under a collective-bargaining agreement, which expires at the end of 2016. NSP-Minnesota also had an additional 272 nuclear operation bargaining employees covered under several collective-bargaining agreements, which expire at various dates in 2015 and 2016.

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

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

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

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

Specific valuation methods include the following:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted net asset values.

Insurance contracts — Insurance contract fair values take into consideration the value of the investments in separate accounts of the insurer, which are priced based on observable inputs.

Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. The fair values for commingled funds, private equity investments and real estate investments are measured using net asset values, which take into consideration the value of underlying fund investments, as well as the other accrued assets and liabilities of a fund, in order to determine a per share market value. The investments in commingled funds may be redeemed for net asset value with proper notice. Proper notice varies by fund and can range from daily with one or two days notice to annually with 90 days notice. Private equity investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate investments may be redeemed with proper notice, which is typically quarterly with 45-90 days notice; however, withdrawals from real estate investments may be delayed or discounted as a result of fund illiquidity. Based on the plan's evaluation of its ability to redeem private equity and real estate investments, fair value measurements for private equity and real estate investments have been assigned a Level 3.

Investments in debt securities — Fair values for debt securities are determined by a third party pricing service using recent trades and observable spreads from benchmark interest rates for similar securities.

Derivative Instruments — Fair values for foreign currency derivatives are determined using pricing models based on the prevailing forward exchange rate of the underlying currencies. The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Pension Benefits

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

In addition to the qualified pension plans, Xcel Energy maintains a supplemental executive retirement plan (SERP) and a nonqualified pension plan. The SERP is maintained for certain executives that were participants in the plan in 2008, when the SERP was closed to new participants. The nonqualified pension plan provides unfunded, nonqualified benefits for compensation that is in excess of the limits applicable to the qualified pension plans. The total obligations of the SERP and nonqualified plan as of Dec. 31, 2014 and 2013 were \$46.5 million and \$36.5 million, respectively, of which \$5.7 million and \$5.3 million was attributable to NSP-Minnesota. In 2014 and 2013, Xcel Energy recognized net benefit cost for financial reporting for the SERP and nonqualified plans of \$4.7 million and \$6.6 million, respectively, of which \$0.5 million in each year was attributable to NSP-Minnesota. Benefits for these unfunded plans are paid out of Xcel Energy's consolidated operating cash flows.

Xcel Energy Inc. and NSP-Minnesota base the investment-return assumption on expected long-term performance for each of the investment types included in the pension asset portfolio and consider the historical returns achieved by the asset portfolio over the past 20-year or longer period, as well as the long-term return levels projected and recommended by investment experts. Xcel Energy Inc. and NSP-Minnesota continually review pension assumptions. The pension cost determination assumes a forecasted mix of investment types over the long term.

- Investment returns in 2014 and 2013 were below the assumed level of 7.25 percent in both years;
- Investment returns in 2012 were above the assumed level of 7.50 percent; and
- In 2015, NSP-Minnesota's expected investment-return assumption is 7.25 percent.

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

The following table presents the target pension asset allocations for NSP-Minnesota at Dec. 31 for the upcoming year:

	2014	2013
Domestic and international equity securities	39%	31%
Long-duration fixed income and interest rate swap securities	23	29
Short-to-intermediate term fixed income securities	14	16
Alternative investments	22	22
Cash	2	2
Total	100%	100%

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

Pension Plan Assets

The following tables present, for each of the fair value hierarchy levels, NSP-Minnesota's pension plan assets that are measured at fair value as of Dec. 31, 2014 and 2013:

(Thousands of Dollars)	Dec. 31, 2014			
	Level 1	Level 2	Level 3	Total
Cash equivalents	\$ 52,506	\$ —	\$ —	\$ 52,506
Derivatives	—	185	—	185
Government securities	—	106,763	—	106,763
Corporate bonds	—	87,821	—	87,821
Asset-backed securities	—	1,073	—	1,073
Mortgage-backed securities	—	3,152	—	3,152
Common stock	29,368	—	—	29,368
Private equity investments	—	—	46,982	46,982
Commingled funds	—	543,008	—	543,008
Real estate	—	—	16,660	16,660
Securities lending collateral obligation and other	—	(6,603)	—	(6,603)
Total	<u>\$ 81,874</u>	<u>\$ 735,399</u>	<u>\$ 63,642</u>	<u>\$ 880,915</u>

(Thousands of Dollars)	Dec. 31, 2013			
	Level 1	Level 2	Level 3	Total
Cash equivalents	\$ 28,078	\$ —	\$ —	\$ 28,078
Derivatives	—	6,073	—	6,073
Government securities	—	43,501	—	43,501
Corporate bonds	—	161,761	—	161,761
Asset-backed securities	—	1,991	—	1,991
Mortgage-backed securities	—	4,436	—	4,436
Common stock	29,384	—	—	29,384
Private equity investments	—	—	48,633	48,633
Commingled funds	—	546,863	—	546,863
Real estate	—	—	14,904	14,904
Securities lending collateral obligation and other	—	2,018	—	2,018
Total	<u>\$ 57,462</u>	<u>\$ 766,643</u>	<u>\$ 63,537</u>	<u>\$ 887,642</u>

The following tables present the changes in NSP-Minnesota's Level 3 pension plan assets for the years ended Dec. 31, 2014, 2013 and 2012:

(Thousands of Dollars)	Jan. 1, 2014	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances and Settlements, Net	Transfers out of Level 3	Dec. 31, 2014
Private equity investments	\$ 48,633	\$ 7,949	\$ (6,785)	\$ (2,815)	\$ —	\$ 46,982
Real estate	14,904	1,104	(1,197)	1,849	—	16,660
Total	<u>\$ 63,537</u>	<u>\$ 9,053</u>	<u>\$ (7,982)</u>	<u>\$ (966)</u>	<u>\$ —</u>	<u>\$ 63,642</u>

(Thousands of Dollars)	Jan. 1, 2013	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances and Settlements, Net	Transfers out of Level 3 ^(a)	Dec. 31, 2013
Asset-backed securities	\$ 4,741	\$ —	\$ —	\$ —	\$ (4,741)	\$ —
Mortgage-backed securities	13,472	—	—	—	(13,472)	—
Private equity investments	54,091	7,018	(11,403)	(1,073)	—	48,633
Real estate	21,978	(833)	1,860	2,920	(11,021)	14,904
Total	<u>\$ 94,282</u>	<u>\$ 6,185</u>	<u>\$ (9,543)</u>	<u>\$ 1,847</u>	<u>\$ (29,234)</u>	<u>\$ 63,537</u>

(a) Transfers out of Level 3 into Level 2 were principally due to diminished use of unobservable inputs that were previously significant to these fair value measurements and were subsequently sold during 2013.

(Thousands of Dollars)	Jan. 1, 2012	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances and Settlements, Net	Transfers out of Level 3	Dec. 31, 2012
Asset-backed securities	\$ 10,188	\$ 1,249	\$ (1,744)	\$ (4,952)	\$ —	\$ 4,741
Mortgage-backed securities	24,413	588	(705)	(10,824)	—	13,472
Private equity investments	54,499	5,985	(7,724)	1,331	—	54,091
Real estate	12,967	6	2,141	6,864	—	21,978
Total	<u>\$ 102,067</u>	<u>\$ 7,828</u>	<u>\$ (8,032)</u>	<u>\$ (7,581)</u>	<u>\$ —</u>	<u>\$ 94,282</u>

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

(Thousands of Dollars)	2014	2013
Accumulated Benefit Obligation at Dec. 31	\$ 1,027,467	\$ 1,002,737
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	\$ 1,062,633	\$ 1,139,356
Service cost	29,699	33,167
Interest cost	47,309	43,734
Plan amendments	—	(3,637)
Actuarial loss (gain)	74,204	(41,173)
Benefit payments	(114,174)	(108,814)
Obligation at Dec. 31	<u>\$ 1,099,671</u>	<u>\$ 1,062,633</u>
(Thousands of Dollars)	2014	2013
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	\$ 887,642	\$ 864,330
Actual return on plan assets	55,332	59,714
Employer contributions	52,115	72,412
Benefit payments	(114,174)	(108,814)
Fair value of plan assets at Dec. 31	<u>\$ 880,915</u>	<u>\$ 887,642</u>
(Thousands of Dollars)	2014	2013
Funded Status of Plans at Dec. 31:		
Funded status ^(a)	\$ (218,756)	\$ (174,991)

^(a) Amounts are recognized in noncurrent liabilities on NSP-Minnesota's consolidated balance sheet.

(Thousands of Dollars)	2014	2013
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	\$ 611,069	\$ 574,062
Prior service cost	5,646	6,582
Total	<u>\$ 616,715</u>	<u>\$ 580,644</u>
(Thousands of Dollars)	2014	2013
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Current regulatory assets	\$ 45,896	\$ 50,623
Noncurrent regulatory assets	570,819	530,021
Total	<u>\$ 616,715</u>	<u>\$ 580,644</u>
Measurement date	Dec. 31, 2014	Dec. 31, 2013

	2014	2013
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	4.11%	4.75%
Expected average long-term increase in compensation level	3.75%	3.75%
Mortality table	RP 2014	RP 2000

Mortality — In 2014, the Society of Actuaries published a new mortality table and projection scale that increased the overall life expectancy of males and females. NSP-Minnesota has reviewed its own population through a credibility analysis and adopted the RP 2014 table with modifications based on its population and specific experience.

Cash Flows — Cash funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the funding requirements of income tax and other pension-related regulations. Required contributions were made in 2012 through 2015 to meet minimum funding requirements.

Total voluntary and required pension funding contributions across all four of Xcel Energy's pension plans were as follows:

- \$90.0 million in January 2015, of which \$32.7 million was attributable to NSP-Minnesota;
- \$130.6 million in 2014, of which \$52.1 million was attributable to NSP-Minnesota;
- \$192.4 million in 2013, of which \$72.4 million was attributable to NSP-Minnesota; and
- \$198.1 million in 2012, of which \$79.6 million was attributable to NSP-Minnesota.

For future years, Xcel Energy and NSP-Minnesota anticipate contributions will be made as necessary.

Plan Amendments — In 2014 there were no plan amendments made which affected the projected benefit obligation. Xcel Energy, which includes NSP-Minnesota, amended the plan in 2013 resulting in a decrease of the projected benefit obligation due to fully insuring the long-term disability benefit for NSP bargaining participants. This decrease was partially offset by an increase to the projected benefit obligation resulting from a change in the discount rate basis for lump sum conversion of annuities for participants in the Xcel Energy Pension Plan.

Benefit Costs — The components of NSP-Minnesota's net periodic pension cost were:

(Thousands of Dollars)	2014	2013	2012
Service cost	\$ 29,699	\$ 33,167	\$ 29,411
Interest cost	47,309	43,734	49,813
Expected return on plan assets	(62,920)	(63,152)	(67,315)
Amortization of prior service cost	936	2,057	11,819
Amortization of net loss	44,785	52,988	41,147
Net periodic pension cost	59,809	68,794	64,875
Costs not recognized due to effects of regulation	(29,485)	(35,455)	(34,917)
Net benefit cost recognized for financial reporting	\$ 30,324	\$ 33,339	\$ 29,958
	2014	2013	2012
Significant Assumptions Used to Measure Costs:			
Discount rate	4.75%	4.00%	5.00%
Expected average long-term increase in compensation level	3.75	3.75	4.00
Expected average long-term rate of return on assets	7.25	7.25	7.50

In addition to the benefit costs in the table above, for the pension plans sponsored by Xcel Energy, Inc., costs are allocated to NSP-Minnesota based on Xcel Energy Services Inc. employees' labor costs. Amounts allocated to NSP-Minnesota were \$10.3 million, \$12.9 million and \$10.8 million in 2014, 2013 and 2012, respectively. Pension costs include an expected return impact for the current year that may differ from actual investment performance in the plan. The return assumption used for 2015 pension cost calculations is 7.25 percent. The cost calculation uses a market-related valuation of pension assets. Xcel Energy, including NSP-Minnesota, uses a calculated value method to determine the market-related value of the plan assets. The market-related value begins with the fair market value of assets as of the beginning of the year. The market-related value is determined by adjusting the fair market value of assets to reflect the investment gains and losses (the difference between the actual investment return and the expected investment return on the market-related value) during each of the previous five years at the rate of 20 percent per year. As these differences between actual investment returns and the expected investment returns are incorporated into the market-related value, the differences are recognized over the expected average remaining years of service for active employees.

Defined Contribution Plans

Xcel Energy, which includes NSP-Minnesota, maintains 401(k) and other defined contribution plans that cover substantially all employees. The expense to these plans for NSP-Minnesota was approximately \$11.1 million in 2014, \$10.4 million in 2013 and \$9.0 million in 2012.

Postretirement Health Care Benefits

Xcel Energy, which includes NSP-Minnesota, has a contributory health and welfare benefit plan that provides health care and death benefits to certain Xcel Energy retirees. The former NSP, which includes NSP-Minnesota, discontinued contributing toward health care benefits for nonbargaining employees retiring after 1998 and for bargaining employees who retired after 1999.

In 1993, Xcel Energy Inc. and NSP-Minnesota adopted accounting guidance regarding other non-pension postretirement benefits and elected to amortize the unrecognized APBO on a straight-line basis over 20 years.

Regulatory agencies for nearly all retail and wholesale utility customers have allowed rate recovery of accrued postretirement benefit costs.

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

The following table presents the target postretirement asset allocations for Xcel Energy Inc. and NSP-Minnesota at Dec. 31 for the upcoming year:

	2014	2013
Domestic and international equity securities	25%	41%
Short-to-intermediate fixed income securities	57	40
Alternative investments	13	13
Cash	5	6
Total	100%	100%

Xcel Energy Inc. and NSP-Minnesota base investment-return assumptions for the postretirement health care fund assets on expected long-term performance for each of the investment types included in the asset portfolio. Assumptions and target allocations are determined at the master trust level. The investment mix at each of Xcel Energy Inc.'s utility subsidiaries may vary from the investment mix of the total asset portfolio. The assets are invested in a portfolio according to Xcel Energy Inc.'s and NSP-Minnesota's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize the necessity of contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the projected allocation of assets to selected asset classes, given the long-term risk, return, correlation and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any particular industry, index, or entity. Market volatility is not considered to be a material factor in postretirement health care costs.

The following tables present, for each of the fair value hierarchy levels, NSP-Minnesota's proportionate allocation of the total postretirement benefit plan assets that are measured at fair value as of Dec. 31, 2014 and 2013:

(Thousands of Dollars)	Dec. 31, 2014			
	Level 1	Level 2	Level 3	Total
Cash equivalents	\$ 115	\$ —	\$ —	\$ 115
Derivatives	—	1	—	1
Government securities	—	213	—	213
Insurance contracts	—	221	—	221
Corporate bonds	—	237	—	237
Asset-backed securities	—	16	—	16
Mortgage-backed securities	—	49	—	49
Commingled funds	—	1,237	—	1,237
Other	—	(8)	—	(8)
Total	\$ 115	\$ 1,966	\$ —	\$ 2,081

(Thousands of Dollars)	Dec. 31, 2013			
	Level 1	Level 2	Level 3	Total
Cash equivalents	\$ 179	\$ —	\$ —	\$ 179
Derivatives	—	(3)	—	(3)
Government securities	—	510	—	510
Insurance contracts	—	461	—	461
Corporate bonds	—	453	—	453
Asset-backed securities	—	29	—	29
Mortgage-backed securities	—	212	—	212
Commingled funds	—	2,606	—	2,606
Other	—	(148)	—	(148)
Total	\$ 179	\$ 4,120	\$ —	\$ 4,299

For the year ended Dec. 31, 2014 there were no assets transferred in or out of Level 3. The following tables present the changes in NSP-Minnesota's Level 3 postretirement benefit plan assets for the years ended Dec. 31, 2013 and 2012:

(Thousands of Dollars)	Jan. 1, 2013	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances and Settlements, Net	Transfers Out of Level 3 ^(a)	Dec. 31, 2013
Asset-backed securities	\$ 9	\$ —	\$ —	\$ —	\$ (9)	\$ —
Mortgage-backed securities	483	—	—	—	(483)	—
Total	\$ 492	\$ —	\$ —	\$ —	\$ (492)	\$ —

(a) Transfers out of Level 3 into Level 2 were principally due to diminished use of unobservable inputs that were previously significant to these fair value measurements and were subsequently sold during 2013.

(Thousands of Dollars)	Jan. 1, 2012	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances and Settlements, Net	Transfers Out of Level 3	Dec. 31, 2012
Asset-backed securities	\$ 119	\$ (4)	\$ 28	\$ (134)	\$ —	\$ 9
Mortgage-backed securities	415	(9)	57	20	—	483
Total	\$ 534	\$ (13)	\$ 85	\$ (114)	\$ —	\$ 492

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

(Thousands of Dollars)	2014	2013
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	\$ 108,232	\$ 124,986
Service cost	187	120
Interest cost	4,993	4,901
Medicare subsidy reimbursements	12	126
Plan participants' contributions	995	2,367
Actuarial gain	(5,742)	(13,385)
Benefit payments	(10,731)	(10,883)
Obligation at Dec. 31	<u>\$ 97,946</u>	<u>\$ 108,232</u>
(Thousands of Dollars)	2014	2013
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	\$ 4,299	\$ 5,818
Actual return on plan assets	3	15
Plan participants' contributions	995	2,367
Employer contributions	7,515	6,982
Benefit payments	(10,731)	(10,883)
Fair value of plan assets at Dec. 31	<u>\$ 2,081</u>	<u>\$ 4,299</u>
(Thousands of Dollars)	2014	2013
Funded Status of Plans at Dec. 31:		
Funded status	<u>\$ (95,865)</u>	<u>\$ (103,933)</u>
Current liabilities	(6,879)	(4,990)
Noncurrent liabilities	(88,986)	(98,943)
Net postretirement amounts recognized on consolidated balance sheets	<u>\$ (95,865)</u>	<u>\$ (103,933)</u>
(Thousands of Dollars)	2014	2013
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	\$ 48,040	\$ 56,899
Prior service credit	(24,505)	(27,541)
Transition obligation	—	2
Total	<u>\$ 23,535</u>	<u>\$ 29,360</u>
(Thousands of Dollars)	2014	2013
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Current regulatory assets	\$ —	\$ 1,679
Noncurrent regulatory assets	22,004	25,800
Deferred income taxes	625	768
Net-of-tax accumulated OCI	906	1,113
Total	<u>\$ 23,535</u>	<u>\$ 29,360</u>
Measurement date	Dec. 31, 2014	Dec. 31, 2013
Significant Assumptions Used to Measure Benefit Obligations:	2014	2013
Discount rate for year-end valuation	4.08%	4.82%
Mortality table	RP 2014	RP 2000
Health care costs trend rate — initial	6.50%	7.00%

Effective Jan. 1, 2015, the initial medical trend rate was decreased from 7.0 percent to 6.5 percent. The ultimate trend assumption remained at 4.5 percent. The period until the ultimate rate is reached is four years. Xcel Energy Inc. and NSP-Minnesota base the medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost increases experienced by the retiree medical plan.

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

(Thousands of Dollars)	One Percentage Point	
	Increase	Decrease
APBO	\$ 10,061	\$ (8,469)
Service and interest components	613	(503)

Cash Flows — The postretirement health care plans have no funding requirements under income tax and other retirement-related regulations other than fulfilling benefit payment obligations, when claims are presented and approved under the plans. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities, as discussed previously. Xcel Energy, which includes NSP-Minnesota, contributed \$17.1 million, \$17.6 million and \$47.1 million during 2014, 2013 and 2012, respectively, of which \$7.5 million, \$7.0 million and \$12.0 million were attributable to NSP-Minnesota. Xcel Energy expects to contribute approximately \$12.8 million during 2015, of which \$9.0 million is attributable to NSP-Minnesota.

Plan Amendments — In 2014 and 2013, there were no plan amendments made which affected the benefit obligation.

Benefit Costs — The components of NSP-Minnesota's net periodic postretirement benefit costs were:

(Thousands of Dollars)	2014	2013	2012
Service cost	\$ 187	\$ 120	\$ 96
Interest cost	4,993	4,901	7,129
Expected return on plan assets	(301)	(417)	(438)
Amortization of transition obligation	—	33	1,346
Amortization of prior service credit	(3,036)	(3,036)	(117)
Amortization of net loss	3,416	5,272	3,204
Net periodic postretirement benefit cost	<u>\$ 5,259</u>	<u>\$ 6,873</u>	<u>\$ 11,220</u>
	<u>2014</u>	<u>2013</u>	<u>2012</u>

Significant Assumptions Used to Measure Costs:

Discount rate	4.82%	4.10%	5.00%
Expected average long-term rate of return on assets	7.00	7.11	6.75

In addition to the benefit costs in the table above, for the postretirement health care plans sponsored by Xcel Energy, Inc., costs are allocated to NSP-Minnesota based on Xcel Energy Services Inc. employees' labor costs.

Projected Benefit Payments

The following table lists NSP-Minnesota's projected benefit payments for the pension and postretirement benefit plans:

(Thousands of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
2015	\$ 86,217	\$ 8,972	\$ 12	\$ 8,960
2016	94,657	8,666	14	8,652
2017	93,692	8,301	14	8,287
2018	92,558	8,053	14	8,039
2019	92,852	7,760	14	7,746
2020-2024	436,328	33,811	79	33,732

Multiemployer Plans

NSP-Minnesota contributes to several union multiemployer pension and other postretirement benefit plans, none of which are individually significant. These plans provide pension and postretirement health care benefits to certain union employees, including electrical workers, boilermakers, and other construction and facilities workers who may perform services for more than one employer during a given period and do not participate in the NSP-Minnesota sponsored pension and postretirement health care plans. Contributing to these types of plans creates risk that differs from providing benefits under NSP-Minnesota sponsored plans, in that if another participating employer ceases to contribute to a multiemployer plan, additional unfunded obligations may need to be funded over time by remaining participating employers.

Contributions to multiemployer plans were as follows for the years ended Dec. 31, 2014, 2013 and 2012. The average number of NSP-Minnesota union employees covered by the multiemployer pension plans decreased to approximately 1,000 in 2014 from approximately 1,100 in 2013. There were no other significant changes to the nature or magnitude of the participation of NSP-Minnesota in multiemployer plans for the years presented:

(Thousands of Dollars)	2014	2013	2012
Multiemployer plan contributions:			
Pension	\$ 20,254	\$ 23,515	\$ 14,984
Other postretirement benefits	273	390	197
Total	<u>\$ 20,527</u>	<u>\$ 23,905</u>	<u>\$ 15,181</u>

8. Other Income (Expense), Net

Other income (expense), net for the years ended Dec. 31 consisted of the following:

(Thousands of Dollars)	2014	2013	2012
Interest income	\$ 4,778	\$ 4,869	\$ 5,364
Other nonoperating income	651	174	825
Insurance policy expense	(4,849)	(5,696)	(5,210)
Other income (expense), net	<u>\$ 580</u>	<u>\$ (653)</u>	<u>\$ 979</u>

9. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

The accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires certain disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance. The three levels in the hierarchy are as follows:

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

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

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

Specific valuation methods include the following:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted net asset values.

Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. The fair values for commingled funds, international equity funds, private equity investments and real estate investments are measured using net asset values, which take into consideration the value of underlying fund investments, as well as the other accrued assets and liabilities of a fund, in order to determine a per-share market value. The investments in commingled funds and international equity funds may be redeemed for net asset value with proper notice. Proper notice varies by fund and can range from daily with one or two days notice to annually with 90 days notice. Private equity investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate investments may be redeemed with proper notice, which is typically quarterly with 45-90 days notice; however, withdrawals from real estate investments may be delayed or discounted as a result of fund illiquidity. Based on NSP-Minnesota's evaluation of its ability to redeem private equity and real estate investments, fair value measurements for private equity and real estate investments have been assigned a Level 3.

Investments in debt securities — Fair values for debt securities are determined by a third party pricing service using recent trades and observable spreads from benchmark interest rates for similar securities.

Interest rate derivatives — The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — The methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations, and are generally assigned a Level 2. When contractual settlements extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable forecasts of long-term forward prices and volatilities on a valuation is evaluated, and may result in Level 3 classification.

Electric commodity derivatives held by NSP-Minnesota include transmission congestion instruments purchased from MISO, PJM, Electric Reliability Council of Texas and NYISO, generally referred to as FTRs. FTRs purchased from an RTO are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path. The value of an FTR is derived from, and designed to offset, the cost of energy congestion, which is caused by overall transmission load and other transmission constraints. In addition to overall transmission load, congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of an FTR. NSP-Minnesota's valuation process for FTRs utilizes complex iterative modeling to predict the impacts of forecasted changes in these drivers of transmission system congestion on the historical pricing of FTR purchases.

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of management's forecasts for several of the inputs to this complex valuation model – including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3. Non-trading monthly FTR settlements are included in fuel and purchased energy cost recovery mechanisms, and therefore changes in the fair value of the yet to be settled portions of most FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of NSP-Minnesota's FTRs relative to its electric utility operations, the numerous unobservable quantitative inputs to the complex model used for valuation of FTRs are insignificant to the consolidated financial statements of NSP-Minnesota.

Non-Derivative Instruments Fair Value Measurements

The NRC requires NSP-Minnesota to maintain a portfolio of investments to fund the costs of decommissioning its nuclear generating plants. Together with all accumulated earnings or losses, the assets of the nuclear decommissioning fund are legally restricted for the purpose of decommissioning the Monticello and PI nuclear generating plants. The fund contains cash equivalents, debt securities, equity securities and other investments – all classified as available-for-sale. NSP-Minnesota uses the MPUC approved asset allocation for the escrow and investment targets by asset class for both the escrow and qualified trust.

NSP-Minnesota recognizes the costs of funding the decommissioning of its nuclear generating plants over the lives of the plants, assuming rate recovery of all costs. Given the purpose and legal restrictions on the use of nuclear decommissioning fund assets, realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund, including any other-than-temporary impairments, are deferred as a component of the regulatory asset for nuclear decommissioning.

Unrealized gains for the nuclear decommissioning fund were \$312.1 million and \$240.3 million at Dec. 31, 2014 and 2013, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were \$74.1 million and \$58.5 million at Dec. 31, 2014 and 2013, respectively.

The following tables present the cost and fair value of NSP-Minnesota's non-derivative instruments with recurring fair value measurements in the nuclear decommissioning fund at Dec. 31, 2014 and 2013:

(Thousands of Dollars)	Dec. 31, 2014				
	Cost	Fair Value			
		Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund ^(a)					
Cash equivalents	\$ 24,184	\$ 24,184	\$ —	\$ —	\$ 24,184
Commingled funds	470,013	—	465,615	—	465,615
International equity funds	80,454	—	78,721	—	78,721
Private equity investments	73,936	—	—	101,237	101,237
Real estate	43,859	—	—	64,249	64,249
Debt securities:					
Government securities	30,674	—	28,808	—	28,808
U.S. corporate bonds	81,463	—	77,562	—	77,562
International corporate bonds	16,950	—	16,341	—	16,341
Municipal bonds	242,282	—	249,201	—	249,201
Asset-backed securities	9,131	—	9,250	—	9,250
Mortgage-backed securities	23,225	—	23,895	—	23,895
Equity securities:					
Common stock	369,751	564,858	—	—	564,858
Total	\$ 1,465,922	\$ 589,042	\$ 949,393	\$ 165,486	\$ 1,703,921

^(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes \$31.4 million of miscellaneous investments.

	Dec. 31, 2013				
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund ^(a)					
Cash equivalents	\$ 33,281	\$ 33,281	\$ —	\$ —	\$ 33,281
Commingled funds	457,986	—	452,227	—	452,227
International equity funds	78,812	—	81,671	—	81,671
Private equity investments	52,143	—	—	62,696	62,696
Real estate	45,564	—	—	57,368	57,368
Debt securities:					
Government securities	34,304	—	27,628	—	27,628
U.S. corporate bonds	80,275	—	83,538	—	83,538
International corporate bonds	15,025	—	15,358	—	15,358
Municipal bonds	241,112	—	232,016	—	232,016
Equity securities:					
Common stock	406,695	581,243	—	—	581,243
Total	\$ 1,445,197	\$ 614,524	\$ 892,438	\$ 120,064	\$ 1,627,026

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes \$28.3 million of miscellaneous investments.

The following tables present the changes in Level 3 nuclear decommissioning fund investments:

(Thousands of Dollars)	Jan. 1, 2014	Purchases	Settlements	Gains Recognized as Regulatory Assets ^(a)	Transfers Out of Level 3	Dec. 31, 2014
Private equity investments	\$ 62,696	\$ 22,078	\$ (286)	\$ 16,749	\$ —	\$ 101,237
Real estate	57,368	8,088	(9,794)	8,587	—	64,249
Total	\$ 120,064	\$ 30,166	\$ (10,080)	\$ 25,336	\$ —	\$ 165,486

(Thousands of Dollars)	Jan. 1, 2013	Purchases	Settlements	Gains Recognized as Regulatory Assets ^(a)	Transfers Out of Level 3 ^(b)	Dec. 31, 2013
Private equity investments	\$ 33,250	\$ 24,201	\$ —	\$ 5,245	\$ —	\$ 62,696
Real estate	39,074	31,626	(18,622)	5,290	—	57,368
Asset-backed securities	2,067	—	—	—	(2,067)	—
Mortgage-backed securities	30,209	—	—	—	(30,209)	—
Total	\$ 104,600	\$ 55,827	\$ (18,622)	\$ 10,535	\$ (32,276)	\$ 120,064

(Thousands of Dollars)	Jan. 1, 2012	Purchases	Settlements	Gains (Losses) Recognized as Regulatory Assets ^(a)	Transfers Out of Level 3	Dec. 31, 2012
Private equity investments	\$ 9,203	\$ 20,671	\$ (1,931)	\$ 5,307	\$ —	\$ 33,250
Real estate	26,395	9,777	(3,611)	6,513	—	39,074
Asset-backed securities	16,501	—	(14,450)	16	—	2,067
Mortgage-backed securities	78,664	33,016	(79,899)	(1,572)	—	30,209
Total	\$ 130,763	\$ 63,464	\$ (99,891)	\$ 10,264	\$ —	\$ 104,600

(a) Gains and losses are deferred as a component of the regulatory asset for nuclear decommissioning.

(b) Transfers out of Level 3 into Level 2 were principally due to diminished use of unobservable inputs that were previously significant to these fair value measurements and were subsequently sold during 2013.

The following table summarizes the final contractual maturity dates of the debt securities in the nuclear decommissioning fund, by asset class, at Dec. 31, 2014:

(Thousands of Dollars)	Final Contractual Maturity				
	Due in 1 Year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years	Total
Government securities	\$ —	\$ —	\$ —	\$ 28,808	\$ 28,808
U.S. corporate bonds	300	15,530	62,838	(1,106)	77,562
International corporate bonds	—	4,212	12,129	—	16,341
Municipal bonds	1,893	35,048	41,530	170,730	249,201
Asset-backed securities	—	—	6,389	2,861	9,250
Mortgage-backed securities	—	—	—	23,895	23,895
Debt securities	<u>\$ 2,193</u>	<u>\$ 54,790</u>	<u>\$ 122,886</u>	<u>\$ 225,188</u>	<u>\$ 405,057</u>

Derivative Instruments Fair Value Measurements

NSP-Minnesota enters into derivative instruments, including forward contracts, futures, swaps and options, for trading purposes and to manage risk in connection with changes in interest rates, utility commodity prices and vehicle fuel prices.

Interest Rate Derivatives — NSP-Minnesota enters into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes.

At Dec. 31, 2014, accumulated other comprehensive losses related to interest rate derivatives included \$0.8 million of net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings, including forecasted amounts for unsettled hedges, as applicable.

Wholesale and Commodity Trading Risk — NSP-Minnesota conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments. NSP-Minnesota's risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee, which is made up of management personnel not directly involved in the activities governed by this policy.

Commodity Derivatives — NSP-Minnesota enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric and natural gas operations, as well as for trading purposes. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, natural gas for resale, FTRs, vehicle fuel, and weather derivatives.

At Dec. 31, 2014, NSP-Minnesota had various vehicle fuel contracts designated as cash flow hedges extending through December 2016. NSP-Minnesota also enters into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers but are not designated as qualifying hedging transactions. Changes in the fair value of non-trading commodity derivative instruments are recorded in OCI or deferred as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. NSP-Minnesota recorded immaterial amounts to income related to the ineffectiveness of cash flow hedges for the years ended Dec. 31, 2014 and 2013.

At Dec. 31, 2014, net gains related to commodity derivative cash flow hedges recorded as a component of accumulated other comprehensive losses included an immaterial amount of net losses expected to be reclassified into earnings during the next 12 months as the hedged transactions occur.

Additionally, NSP-Minnesota enters into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving its electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in electric operating revenue, net of amounts credited to customers under margin-sharing mechanisms.

The following table details the gross notional amounts of commodity forwards, options and FTRs at Dec. 31:

(Amounts in Thousands) ^{(a)(b)}	2014	2013
MWh of electricity	49,431	52,107
MMBtu of natural gas	173	2,470
Gallons of vehicle fuel	155	265

(a) Amounts are not reflective of net positions in the underlying commodities.

(b) Notional amounts for options are included on a gross basis, but are weighted for the probability of exercise.

Consideration of Credit Risk and Concentrations — NSP-Minnesota continuously monitors the creditworthiness of the counterparties to its interest rate derivatives and commodity derivative contracts prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment, as well as an assessment of the impact of NSP-Minnesota's own credit risk when determining the fair value of derivative liabilities, the impact of considering credit risk was immaterial to the fair value of unsettled commodity derivatives presented in the consolidated balance sheets.

NSP-Minnesota employs additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees, standardized master netting agreements and termination provisions that allow for offsetting of positive and negative exposures. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided.

NSP-Minnesota's most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to its wholesale, trading and non-trading commodity activities. At Dec. 31, 2014, five of NSP-Minnesota's 10 most significant counterparties for these activities, comprising \$23.4 million or 33 percent of this credit exposure, had investment grade credit ratings from Standard & Poor's, Moody's or Fitch Ratings. The remaining five most significant counterparties, comprising \$12.3 million or 17 percent of this credit exposure at Dec. 31, 2014, were not rated by these agencies, but based on NSP-Minnesota's internal analysis, had credit quality consistent with investment grade. All 10 of these significant counterparties are municipal or cooperative electric entities, or other utilities.

Financial Impact of Qualifying Cash Flow Hedges — The impact of qualifying interest rate and vehicle fuel cash flow hedges on NSP-Minnesota's accumulated other comprehensive loss, included in the consolidated statements of common stockholder's equity and in the consolidated statements of comprehensive income, is detailed in the following table:

(Thousands of Dollars)	2014	2013	2012
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	\$ (20,609)	\$ (21,393)	\$ (11,729)
After-tax net unrealized (losses) gains related to derivatives accounted for as hedges	(89)	5	(9,889)
After-tax net realized losses on derivative transactions reclassified into earnings	789	779	225
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	<u>\$ (19,909)</u>	<u>\$ (20,609)</u>	<u>\$ (21,393)</u>

The following tables detail the impact of derivative activity during the years ended Dec. 31, 2014, 2013 and 2012 on accumulated other comprehensive loss, regulatory assets and liabilities, and income:

	Year Ended Dec. 31, 2014				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		
	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains Recognized During the Period in Income
(Thousands of Dollars)					
Derivatives designated as cash flow hedges					
Interest rate	\$ —	\$ —	\$ 1,387 ^(a)	\$ —	\$ —
Vehicle fuel and other commodity	(150)	—	(30) ^(b)	—	—
Total	<u>\$ (150)</u>	<u>\$ —</u>	<u>\$ 1,357</u>	<u>\$ —</u>	<u>\$ —</u>
Other derivative instruments					
Commodity trading	\$ —	\$ —	\$ —	\$ —	\$ 751 ^(c)
Electric commodity	—	(4,385)	—	(17,200) ^(d)	—
Natural gas commodity	—	4,576	—	(8,584) ^(e)	(2,627) ^(e)
Other commodity	—	—	—	—	643 ^(c)
Total	<u>\$ —</u>	<u>\$ 191</u>	<u>\$ —</u>	<u>\$ (25,784)</u>	<u>\$ (1,233)</u>
	Year Ended Dec. 31, 2013				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		
	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains Recognized During the Period in Income
(Thousands of Dollars)					
Derivatives designated as cash flow hedges					
Interest rate	\$ —	\$ —	\$ 1,388 ^(a)	\$ —	\$ —
Vehicle fuel and other commodity	15	—	(49) ^(b)	—	—
Total	<u>\$ 15</u>	<u>\$ —</u>	<u>\$ 1,339</u>	<u>\$ —</u>	<u>\$ —</u>
Other derivative instruments					
Commodity trading	\$ —	\$ —	\$ —	\$ —	\$ 11,220 ^(c)
Electric commodity	—	65,884	—	(52,796) ^(d)	—
Natural gas commodity	—	1,039	—	368 ^(e)	(393) ^(d)
Total	<u>\$ —</u>	<u>\$ 66,923</u>	<u>\$ —</u>	<u>\$ (52,428)</u>	<u>\$ 10,827</u>

	Year Ended Dec. 31, 2012				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		Pre-Tax Gains Recognized During the Period in Income
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	\$ (16,832)	\$ —	\$ 490 ^(a)	\$ —	\$ —
Vehicle fuel and other commodity	58	—	(109) ^(b)	—	—
Total	<u>\$ (16,774)</u>	<u>\$ —</u>	<u>\$ 381</u>	<u>\$ —</u>	<u>\$ —</u>
Other derivative instruments					
Commodity trading	\$ —	\$ —	\$ —	\$ —	\$ 12,224 ^(c)
Electric commodity	—	44,162	—	(39,999) ^(d)	—
Natural gas commodity	—	(2,662)	—	16,158 ^(e)	—
Total	<u>\$ —</u>	<u>\$ 41,500</u>	<u>\$ —</u>	<u>\$ (23,841)</u>	<u>\$ 12,224</u>

(a) Amounts are recorded to interest charges.

(b) Amounts are recorded to O&M expenses.

(c) Amounts are recorded to electric operating revenues. Portions of these gains and losses are subject to sharing with electric customers through margin-sharing mechanisms and deducted from gross revenue, as appropriate.

(d) Amounts are recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

(e) Amounts are recorded to cost of natural gas sold and transported. These derivative settlement gains and losses are shared with natural gas customers through purchased natural gas cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

NSP-Minnesota had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2014, 2013 and 2012. Therefore, no gains or losses from fair value hedges or related hedged transactions were recognized for these periods.

Credit Related Contingent Features — Contract provisions for derivative instruments that NSP-Minnesota enters into, including those recorded to the consolidated balance sheet at fair value, as well as those accounted for as normal purchase-normal sale contracts and therefore not reflected on the balance sheet, may require the posting of collateral or settlement of the contracts for various reasons, including if NSP-Minnesota is unable to maintain its credit ratings. At Dec. 31, 2014 and 2013, no derivative instruments in a liability position would have required the posting of collateral or settlement of outstanding contracts if the credit ratings of NSP-Minnesota were downgraded below investment grade.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that NSP-Minnesota's ability to fulfill its contractual obligations is reasonably expected to be impaired. NSP-Minnesota had no collateral posted related to adequate assurance clauses in derivative contracts as of Dec. 31, 2014 and 2013.

Recurring Fair Value Measurements — The following table presents for each of the fair value hierarchy levels, NSP-Minnesota's derivative assets and liabilities measured at fair value on a recurring basis at Dec. 31, 2014:

	Dec. 31, 2014						
(Thousands of Dollars)	Fair Value			Fair Value	Counterparty		
	Level 1	Level 2	Level 3	Total	Netting ^(b)	Total	
Current derivative assets							
Other derivative instruments:							
Commodity trading	\$ —	\$ 14,326	\$ 4,732	\$ 19,058	\$ (3,240)	\$ 15,818	
Electric commodity	—	—	37,051	37,051	(1,512)	35,539	
Natural gas commodity	—	295	—	295	(4)	291	
Total current derivative assets	<u>\$ —</u>	<u>\$ 14,621</u>	<u>\$ 41,783</u>	<u>\$ 56,404</u>	<u>\$ (4,756)</u>	51,648	
PPAs ^(a)						8,516	
Current derivative instruments						<u>\$ 60,164</u>	
Noncurrent derivative assets							
Other derivative instruments:							
Commodity trading	\$ —	\$ 17,617	\$ —	\$ 17,617	\$ (4,151)	\$ 13,466	
Total noncurrent derivative assets	<u>\$ —</u>	<u>\$ 17,617</u>	<u>\$ —</u>	<u>\$ 17,617</u>	<u>\$ (4,151)</u>	13,466	
PPAs ^(a)						1,968	
Noncurrent derivative instruments						<u>\$ 15,434</u>	
Current derivative liabilities							
Derivatives designated as cash flow hedges:							
Vehicle fuel and other commodity	\$ —	\$ 65	\$ —	\$ 65	\$ —	\$ 65	
Other derivative instruments:							
Commodity trading	—	7,974	—	7,974	(7,974)	—	
Electric commodity	—	—	1,512	1,512	(1,512)	—	
Total current derivative liabilities	<u>\$ —</u>	<u>\$ 8,039</u>	<u>\$ 1,512</u>	<u>\$ 9,551</u>	<u>\$ (9,486)</u>	65	
PPAs ^(a)						12,229	
Current derivative instruments						<u>\$ 12,294</u>	
Noncurrent derivative liabilities							
Derivatives designated as cash flow hedges:							
Vehicle fuel and other commodity	\$ —	\$ 56	\$ —	\$ 56	\$ —	\$ 56	
Other derivative instruments:							
Commodity trading	—	6,890	—	6,890	(6,033)	857	
Total noncurrent derivative liabilities	<u>\$ —</u>	<u>\$ 6,946</u>	<u>\$ —</u>	<u>\$ 6,946</u>	<u>\$ (6,033)</u>	913	
PPAs ^(a)						134,123	
Noncurrent derivative instruments						<u>\$ 135,036</u>	

(a) In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting, NSP-Minnesota began recording several long-term PPAs at fair value due to accounting requirements related to underlying price adjustments. As these purchases are recovered through normal regulatory recovery mechanisms in the respective jurisdictions, the changes in fair value for these contracts were offset by regulatory assets and liabilities. During 2006, NSP-Minnesota qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

(b) NSP-Minnesota nets derivative instruments and related collateral in its consolidated balance sheet when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Dec. 31, 2014. At Dec. 31, 2014, derivative assets and liabilities include no obligations to return cash collateral and rights to reclaim cash collateral of \$6.6 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

The following table presents for each of the fair value hierarchy levels, NSP-Minnesota's derivative assets and liabilities measured at fair value on a recurring basis at Dec. 31, 2013:

	Dec. 31, 2013						
	Fair Value			Fair Value Total	Counterparty Netting ^(b)	Total	
(Thousands of Dollars)	Level 1	Level 2	Level 3				
Current derivative assets							
Derivatives designated as cash flow hedges:							
Vehicle fuel and other commodity	\$ —	\$ 48	\$ —	\$ 48	\$ —	\$ 48	
Other derivative instruments:							
Commodity trading	—	17,854	1,167	19,021	(6,718)	12,303	
Electric commodity	—	—	30,692	30,692	(1,723)	28,969	
Natural gas commodity	—	1,986	—	1,986	—	1,986	
Total current derivative assets	\$ —	\$ 19,888	\$ 31,859	\$ 51,747	\$ (8,441)	43,306	
PPAs ^(a)						23,420	
Current derivative instruments						\$ 66,726	
Noncurrent derivative assets							
Derivatives designated as cash flow hedges:							
Vehicle fuel and other commodity	\$ —	\$ 16	\$ —	\$ 16	\$ (16)	\$ —	
Other derivative instruments:							
Commodity trading	—	32,074	3,395	35,469	(9,071)	26,398	
Total noncurrent derivative assets	\$ —	\$ 32,090	\$ 3,395	\$ 35,485	\$ (9,087)	26,398	
PPAs ^(a)						10,483	
Noncurrent derivative instruments						\$ 36,881	
Current derivative liabilities							
Other derivative instruments:							
Commodity trading	\$ —	\$ 8,108	\$ 1,804	\$ 9,912	\$ (9,912)	\$ —	
Electric commodity	—	—	1,723	1,723	(1,723)	—	
Total current derivative liabilities	\$ —	\$ 8,108	\$ 3,527	\$ 11,635	\$ (11,635)	—	
PPAs ^(a)						13,066	
Current derivative instruments						\$ 13,066	
Noncurrent derivative liabilities							
Other derivative instruments:							
Commodity trading	\$ —	\$ 14,382	\$ —	\$ 14,382	\$ (10,137)	\$ 4,245	
Total noncurrent derivative liabilities	\$ —	\$ 14,382	\$ —	\$ 14,382	\$ (10,137)	4,245	
PPAs ^(a)						147,406	
Noncurrent derivative instruments						\$ 151,651	

(a) In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting, NSP-Minnesota began recording several long-term PPAs at fair value due to accounting requirements related to underlying price adjustments. As these purchases are recovered through normal regulatory recovery mechanisms in the respective jurisdictions, the changes in fair value for these contracts were offset by regulatory assets and liabilities. During 2006, NSP-Minnesota qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

(b) NSP-Minnesota nets derivative instruments and related collateral in its consolidated balance sheet when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Dec. 31, 2013. At Dec. 31, 2013, derivative assets and liabilities include no obligations to return cash collateral and rights to reclaim cash collateral of \$4.2 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

The following table presents the changes in Level 3 commodity derivatives for the years ended Dec. 31, 2014, 2013 and 2012:

(Thousands of Dollars)	Year Ended Dec. 31		
	2014	2013	2012
Balance at Jan. 1	\$ 31,727	\$ 16,649	\$ 12,417
Purchases	84,762	51,541	37,595
Settlements	(101,690)	(45,199)	(44,950)
Transfers out of Level 3	(1,093)	—	—
Net transactions recorded during the period:			
Gains recognized in earnings ^(a)	10,692	3,947	463
Gains recognized as regulatory liabilities	15,873	4,789	11,124
Balance at Dec. 31	<u>\$ 40,271</u>	<u>\$ 31,727</u>	<u>\$ 16,649</u>

(a) These amounts relate to commodity derivatives held at the end of the period.

NSP-Minnesota recognizes transfers between levels as of the beginning of each period. The transfer of amounts from Level 3 to Level 2 in the year ended Dec. 31, 2014 was due to the valuation of certain long-term derivative contracts for which observable commodity pricing forecasts became a more significant input during the period. There were no transfers of amounts between levels for derivative instruments for the years ended Dec. 31, 2013 and 2012.

Fair Value of Long-Term Debt

As of Dec. 31, 2014 and 2013, other financial instruments for which the carrying amount did not equal fair value were as follows:

(Thousands of Dollars)	2014		2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	\$ 4,188,682	\$ 4,803,735	\$ 3,888,732	\$ 4,099,745

The fair value of NSP-Minnesota's long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. The fair value estimates are based on information available to management as of Dec. 31, 2014 and 2013, and given the observability of the inputs to these estimates, the fair values presented for long-term debt have been assigned a Level 2.

10. Rate Matters

Pending and Recently Concluded Regulatory Proceedings — MPUC

Minnesota 2014 Multi-Year Electric Rate Case — In November 2013, NSP-Minnesota filed a two-year, electric rate case with the MPUC. The rate case is based on a requested ROE of 10.25 percent, a 52.5 percent equity ratio, a 2014 average electric rate base of \$6.67 billion and an additional average rate base of \$412 million in 2015. The NSP-Minnesota electric rate case initially reflected a requested increase in revenues of approximately \$193 million or 6.9 percent in 2014 and an additional \$98 million or 3.5 percent in 2015. The request includes a proposed rate moderation plan for 2014 and 2015.

NSP-Minnesota's moderation plan includes the acceleration of the eight-year amortization of the excess depreciation reserve and the use of expected funds from the DOE for settlement of certain claims. These DOE refunds would be in excess of amounts needed to fund NSP-Minnesota's decommissioning expense. The interim rate adjustments are primarily associated with ROE, Monticello LCM/EPU project costs and NSP-Minnesota's request to amortize amounts associated with the canceled PI EPU project.

In December 2013, the MPUC approved interim rates of \$127 million, effective Jan. 3, 2014, subject to refund. The MPUC determined that the costs of Sherco Unit 3 would be allowed in interim rates, and that NSP-Minnesota's request to accelerate the depreciation reserve amortization was a permissible adjustment to its interim rate request.

In August 2014, NSP-Minnesota revised its requested rate increase to \$142.2 million for 2014 and to \$106.0 million for 2015, for a total combined unadjusted increase of \$248.2 million.

In December 2014, the ALJ issued her recommendations in the NSP-Minnesota electric rate case. While the report did not quantify the overall rate increases, NSP-Minnesota estimates that her recommendations would result in a rate increase of \$69.1 million in 2014 and an incremental rate increase of \$122.4 million in 2015. In addition, she recommended an ROE of 9.77 percent and an equity ratio of 52.5 percent.

The following table summarizes the estimated impact of the ALJ's recommendation, DOC's previously filed surrebuttal testimony and NSP-Minnesota's revised request and includes certain estimated adjustments:

2014 Rate Request (Millions of Dollars)	ALJ	DOC	NSP-Minnesota
NSP-Minnesota's filed rate request	\$ 192.7	\$ 192.7	\$ 192.7
Sales forecast (true-up to 12 months of actual weather-normalized sales)	(15.8)	(43.2)	(15.8)
ROE	(28.4)	(36.2)	—
Monticello EPU cost recovery	(31.3)	(33.9)	—
Monticello EPU depreciation deferral	—	—	(12.2)
Property taxes	(9.0)	(9.0)	(9.0)
PI EPU cost recovery	(5.1)	(5.1)	(5.1)
Health care, pension and other benefits	(1.9)	(11.4)	(1.9)
Other, net	(5.2)	(8.0)	(6.5)
Total recommendation 2014 — unadjusted	\$ 96.0	\$ 45.9	\$ 142.2
Estimated true-up adjustments:			
Sales forecast ^(a)	\$ (22.7)	\$ 4.7	\$ (22.7)
Property taxes ^(b)	(4.2)	(4.2)	(4.2)
Total recommendation 2014 — adjusted	\$ 69.1	\$ 46.4	\$ 115.3

2015 Rate Request (Millions of Dollars)	ALJ	DOC	NSP-Minnesota
NSP-Minnesota's filed rate request	\$ 98.5	\$ 98.5	\$ 98.5
Monticello EPU cost recovery	29.1	29.1	—
Monticello EPU cost disallowance ^(c)	—	(10.2)	—
Excess depreciation reserve adjustment ^(d)	—	(22.7)	—
Depreciation	—	(17.5)	—
Monticello EPU depreciation deferral	—	—	1.6
Monticello EPU step increase	—	—	10.1
Property taxes	(3.3)	(3.3)	(3.3)
Production tax credits to be included in base rates	(11.1)	(11.1)	(11.1)
DOE settlement proceeds	10.1	10.1	10.1
Emission chemicals	(1.6)	(1.6)	(1.6)
Other, net	0.7	(4.8)	1.7
Total recommendation 2015 step increase	\$ 122.4	\$ 66.5	\$ 106.0

Unadjusted cumulative total for 2014 and 2015 step increase	\$ 218.4	\$ 112.4	\$ 248.2
Estimated adjusted cumulative total for 2014 and 2015 step increase	\$ 191.5	\$ 112.9	\$ 221.3

(a) The true-up adjustment for the sales forecast reflects weather-normalized sales through December 2014.

(b) The true-up adjustment for property taxes reflects NSP-Minnesota's 2014 year end property tax accruals.

(c) In July 2014, the DOC recommended a cost disallowance of approximately \$71.5 million on a Minnesota jurisdictional basis which equates to a total NSP System disallowance of approximately \$94 million. This would reduce NSP-Minnesota's revenue requirement by approximately \$10.2 million in 2015.

(d) Adjustment is due to timing differences and/or methodology of accelerating amortization of the excess depreciation reserve over three years.

The ALJ recommended no recovery of the Monticello EPU project costs in 2014, accepting the DOC's argument that the EPU portion was not used and useful in 2014 and should be treated as a 2015 step project. NSP-Minnesota fully met the NRC's requirements for the EPU as of Dec. 31, 2014. NSP-Minnesota is currently executing the power ascension plan consistent with the NRC license amendment approval and as of Dec. 31, 2014 had operated the plant using 56 MW of the additional 71 MW from the EPU. The full 71 MW of additional EPU output is expected to be attained in the first half of 2015. Although the final NRC requirements have been met, rate recovery is still subject to true-up. The ALJ recommendation does not reflect any potential adjustments for the pending Monticello prudence review.

The ALJ did not make a recommendation on the use of the surplus depreciation reserve in NSP-Minnesota's rate moderation proposal. The table above reflects NSP-Minnesota's filed position for the use of the proposed amortization of the surplus depreciation reserve.

The ALJ also recommended adoption of a full decoupling pilot for the residential and small C&I classes, based on actual sales, effective the month after the MPUC issues its final order in 2015. Full decoupling would eliminate the impact of weather variability on electric sales for the residential and small C&I classes for NSP-Minnesota.

NSP-Minnesota has also filed a plan for any potential refund that treats the multi-year case as a single period. In January 2015, the DOC recommended an alternative option that views each year of the multi-year case separately, which would result in lower 2015 revenues.

A current regulatory liability representing NSP-Minnesota's best estimate of a refund obligation for 2014 associated with interim rates was recorded as of Dec. 31, 2014. The estimated amount is generally consistent with the ALJ recommendation.

The MPUC is expected to deliberate on March 26, 2015 and a final order is anticipated in the second quarter of 2015.

Nuclear Project Prudence Investigation — In 2013, NSP-Minnesota completed the Monticello LCM/EPU project. The multi-year project extended the life of the facility and increased the capacity from 600 to 671 MW. Monticello LCM/EPU project expenditures were approximately \$665 million. Total capitalized costs were approximately \$748 million, which includes AFUDC. In 2008, project expenditures were initially estimated at approximately \$320 million, excluding AFUDC.

In 2013, the MPUC initiated an investigation to determine whether the final costs for the Monticello LCM/EPU project were prudent.

NSP-Minnesota filed a report to support the prudence of the incurred costs. The filing indicated the increase in costs was primarily attributable to three factors: (1) the original estimate was based on a high level conceptual design and the project scope increased as the actual conditions of the plant were incorporated into the design; (2) implementation difficulties, including the amount of work that occurred in confined and radioactive or electrically sensitive spaces and NSP-Minnesota's and its vendors' ability to attract and retain experienced workers; and (3) additional NRC licensing related requests over the five-plus year application process.

The cost deviation is in line with similar nuclear upgrade projects undertaken by other utilities. In addition, the project remains economically beneficial to customers. NSP-Minnesota has received all necessary licenses from the NRC for the Monticello EPU, and as of Dec. 31, 2014, has fully complied with the NRC's license requirements for higher power levels.

In July 2014, the DOC filed testimony and recommended a disallowance of recovery of approximately \$71.5 million of project costs on a Minnesota jurisdictional basis.

In August 2014, the OAG filed rebuttal testimony and recommended a disallowance of recovery of \$321 million for the entire NSP System (based on a total capitalized cost of \$748 million), and no return on \$107 million. NSP-Minnesota believes the costs of the project were prudent and its decisions and actions do not warrant a disallowance.

In February 2015, an ALJ issued his report finding that NSP-Minnesota was imprudent in managing the project. Consistent with the DOC's position, the ALJ proposed: (1) 85 percent of the project cost be assigned to EPU costs and applied the DOC's cost-effectiveness test; and (2) disallowance of recovery of approximately \$71.5 million of EPU costs, resulting in a reduction of \$10.24 million to the 2015 revenue requirement on a Minnesota jurisdictional basis. This would equate to a total NSP System disallowance of approximately \$94 million if the MPUC and other state commissions accepted this recommendation. NSP-Minnesota plans to file exceptions to the ALJ's report with the MPUC.

On Feb. 12, 2015, NSP-Minnesota, Xcel Large Industrials and the OAG filed exceptions to the ALJ's Report, advocating their initial positions. On Feb. 17, 2015, reply comments were filed by various parties, including NSP-Minnesota. Oral arguments are scheduled to be held on March 3, 2015.

NSP-Minnesota does not expect a delay to the scheduled proceedings and a final MPUC order is anticipated in the second quarter of 2015. The MPUC decision for the Monticello prudence review is expected to be reflected in the final results of NSP-Minnesota's pending Minnesota 2014 Multi-Year electric rate case.

NSP-Minnesota – 2015 Transmission Cost Recovery Rate Filing — In October 2014, the 2015 NSP-Minnesota TCR filing was filed with the MPUC, requesting recovery of \$65.8 million of 2015 transmission investment costs not previously included in electric base rates. An MPUC decision is anticipated in the second quarter of 2015, with implementation of new rates soon after approval.

PI Nuclear Plant EPU — In 2009, the MPUC granted NSP-Minnesota a CON for an EPU project at the PI nuclear generating plant. The total estimated cost of the EPU was \$294 million, of which approximately \$78.9 million had been incurred through 2012, including AFUDC of approximately \$12.8 million. Subsequently, NSP-Minnesota made a change of circumstances filing notifying the MPUC that there were changes in the size, timing and cost estimates for this project, revisions to economic and project design analysis and changes due to the estimated impact of revised scheduled outages. The information indicated reductions to the estimated benefit of the uprate project. As a result, NSP-Minnesota concluded that further investment in this project would not benefit customers. In February 2013, the MPUC issued an order terminating the CON for the PI EPU project.

NSP-Minnesota plans to address recovery of incurred costs in rate cases for each of the NSP-Minnesota jurisdictions. As noted, NSP-Minnesota is seeking recovery in Minnesota in its pending Minnesota 2014 Multi-Year electric rate case. In December 2014, NSP-Minnesota filed a request with the FERC for approval to recover a portion of the costs from NSP-Wisconsin through the Interchange Agreement commencing Jan. 1, 2016. The request is pending FERC action. NSP-Wisconsin plans to seek cost recovery in future rate cases. Based on the outcome of the December 2012 MPUC decision, EPU costs incurred to date were compared to the discounted value of the estimated future rate recovery based on past jurisdictional precedent, resulting in a \$10.1 million pretax charge in December 2012 which is included in O&M expense for that year. The remaining PI EPU costs were deferred for future amortization corresponding with rate recovery in various NSP jurisdictions.

Pending Regulatory Proceedings — SDPUC

South Dakota 2015 Electric Rate Case — In June 2014, NSP-Minnesota filed a request with the SDPUC to increase South Dakota electric rates by \$15.6 million annually, or 8.0 percent, effective Jan. 1, 2015. The request is based on a 2013 HTY adjusted for certain known and measurable changes for 2014 and 2015, a requested ROE of 10.25 percent, an average rate base of \$433.2 million and an equity ratio of 53.86 percent. This request reflects NSP-Minnesota's proposal to move recovery of approximately \$9.0 million for certain TCR rider and Infrastructure rider projects to base rates.

Interim rates of \$15.6 million, subject to refund, went into effect in January 2015. At this time, the case is in the discovery phase and further procedure scheduling may be established, as necessary during the first quarter of 2015. Final rates are anticipated to be effective mid-2015.

Electric, Purchased Gas and Resource Adjustment Clauses

CIP and CIP Rider — In December 2012, the MPUC approved reductions to the CIP financial incentive mechanisms effective for the 2013 through 2015 program years. Based on the approved savings goals, the estimated average annual electric and natural gas incentives are \$30.6 million and \$3.6 million, respectively.

CIP expenses are recovered through base rates and a rider that is adjusted annually.

- In December 2014, the MPUC approved NSP-Minnesota's 2013 CIP electric and natural gas financial incentives totaling \$42.7 million and \$5.4 million, respectively.
- In addition, the MPUC approved NSP-Minnesota's proposed 2014 to 2015 electric and natural gas CIP riders. NSP-Minnesota estimates 2015 recovery of \$15.5 million of electric CIP expenses and \$6.0 million of natural gas CIP expenses.
- This proposed recovery through the riders is in addition to an estimated \$86.9 million and \$3.7 million through electric and gas base rates, respectively.

NSP-Minnesota – Gas Utility Infrastructure Cost (GUIC) Rider — In August 2014, NSP-Minnesota filed a GUIC rider with the MPUC for approval to recover the cost of natural gas infrastructure investments in Minnesota to improve safety and reliability. Costs include funding for pipeline assessments as well as deferred costs from NSP-Minnesota's existing sewer separation and pipeline integrity management programs. Sewer separation costs stem from the inspection of sewer lines and the redirection of gas pipes in the event their paths are in conflict. NSP-Minnesota requested recovery of approximately \$14.9 million from Minnesota gas utility customers beginning Jan. 1, 2015, including \$4.8 million of deferred sewer separation and integrity management costs which is the 2015 portion of a five year amortization. In December 2014, the MPUC approved the GUIC rider for \$14.7 million, with an effective date of Feb. 1, 2015.

Pending Regulatory Proceedings — FERC

MISO ROE Complaint/ROE Adder — In November 2013, a group of customers filed a complaint at the FERC against MISO transmission owners, including NSP-Minnesota and NSP-Wisconsin. The complaint argued for a reduction in the ROE applicable to transmission formula rates in the MISO region from 12.38 percent to 9.15 percent, a prohibition on capital structures in excess of 50 percent equity, and the removal of ROE adders (including those for RTO membership and being an independent transmission company), effective Nov. 12, 2013.

In June 2014, the FERC issued an order in a different ROE proceeding adopting a new ROE methodology for electric utilities. The new ROE methodology requires electric utilities to use a two-step discounted cash flow analysis to estimate cost of equity that incorporates both short-term and long-term growth projections.

In October 2014, the FERC upheld the determination of the long-term growth rate to be used together with a short term growth rate in its new ROE methodology. The FERC separately set the ROE complaint against the MISO transmission owners for settlement judge and hearing procedures. The FERC directed parties to apply the new ROE methodology, but denied the complaints related to equity capital structures and ROE adders. The FERC established a Nov. 12, 2013 refund effective date. The settlement judge procedures were unsuccessful. FERC action is pending. In January 2015, the ROE complaint was set for full hearing procedures, with an ALJ initial decision to be issued by November 2015 and a FERC order issued no earlier than 2016.

In November 2014, the MISO transmission owners filed a request for FERC approval of a 50 basis point RTO membership ROE adder, with collection deferred until resolution of the ROE complaint. In January 2015, the FERC approved the ROE adder, subject to the outcome of the ROE complaint. The total ROE, including the RTO membership adder, may not exceed the top of the discounted cash flow range under the new ROE methodology. In 2015, several intervenors sought rehearing of the commission order.

In February 2015, a separate group of customers filed an additional complaint proposing to reduce the MISO region ROE to 8.67 percent, prior to any 50 basis point RTO adder, with a refund effective date of Feb. 12, 2015. Answers to the complaint are to be filed by March 2015.

NSP-Minnesota recorded a current liability representing the current best estimate of a refund obligation associated with the new ROE as of Dec. 31, 2014. The new FERC ROE methodology is estimated to reduce transmission revenue, net of expense, between \$5 million and \$7 million annually for the NSP System.

11. Commitments and Contingencies

Commitments

Capital Commitments — NSP-Minnesota has made commitments in connection with a portion of its projected capital expenditures. NSP-Minnesota's capital commitments primarily relate to the following major projects:

Wind Projects — In October 2013, the MPUC approved two projects totaling 350 MW that will be owned by NSP-Minnesota. In 2014, the NDPSC approved the prudence of the Border Winds Project. The Pleasant Valley wind farm in Minnesota and the Border Winds wind farm projects in North Dakota are anticipated to be operational in late 2015.

Fuel Contracts — NSP-Minnesota has entered into various long-term commitments for the purchase and delivery of a significant portion of its current coal, nuclear fuel and natural gas requirements. These contracts expire in various years between 2015 and 2033. NSP-Minnesota is required to pay additional amounts depending on actual quantities shipped under these agreements.

The estimated minimum purchases for NSP-Minnesota under these contracts as of Dec. 31, 2014, are as follows:

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas supply	Natural gas storage and transportation
2015	\$ 315.2	\$ 90.3	\$ 60.3	\$ 99.5
2016	172.6	121.8	5.4	97.9
2017	50.3	121.0	2.9	84.4
2018	30.1	65.6	—	43.5
2019	—	128.5	—	38.1
Thereafter	—	641.4	—	212.0
Total ^(a)	<u>\$ 568.2</u>	<u>\$ 1,168.6</u>	<u>\$ 68.6</u>	<u>\$ 575.4</u>

(a) Includes amounts allocated to NSP-Wisconsin through intercompany charges.

Additional expenditures for fuel and natural gas storage and transportation will be required to meet expected future electric generation and natural gas needs. NSP-Minnesota's risk of loss, in the form of increased costs from market price changes in fuel, is mitigated through the use of natural gas and energy cost-rate adjustment mechanisms, which provide for pass-through of most fuel, storage and transportation costs to customers.

PPAs — NSP-Minnesota has entered into PPAs with other utilities and energy suppliers with expiration dates through 2033 for purchased power to meet system load and energy requirements and to meet operating reserve obligations. In general, these agreements provide for energy payments, based on actual energy delivered and capacity payments. Certain PPAs accounted for as executory contracts also contain minimum energy purchase commitments. Capacity and energy payments are typically contingent on the independent power producing entity meeting certain contract obligations, including plant availability requirements. Certain contractual payments are adjusted based on market indices. The effects of price adjustments on our financial results are mitigated through purchased energy cost recovery mechanisms.

Included in electric fuel and purchased power expenses for PPAs, accounted for as executory contracts, were payments for capacity of \$107.9 million, \$106.0 million and \$106.2 million in 2014, 2013 and 2012, respectively. At Dec. 31, 2014, the estimated future payments for capacity and energy that NSP-Minnesota is obligated to purchase pursuant to these executory contracts, subject to availability, are as follows:

(Millions of Dollars)	Capacity	Energy ^(a)
2015	\$ 105.7	\$ 83.4
2016	91.0	81.6
2017	84.7	87.3
2018	52.8	93.2
2019	53.6	98.7
Thereafter	350.0	767.9
Total ^(b)	<u>\$ 737.8</u>	<u>\$ 1,212.1</u>

(a) Excludes contingent energy payments for renewable energy PPAs.

(b) Includes amounts allocated to NSP-Wisconsin through intercompany charges.

Additional energy payments under these PPAs and PPAs accounted for as operating leases will be required to meet expected future electric demand.

Leases — NSP-Minnesota leases a variety of equipment and facilities used in the normal course of business. These leases, primarily for office space, railcars, generating facilities, trucks, aircraft, cars and power-operated equipment, are accounted for as operating leases. Total expenses under operating lease obligations were approximately \$81.0 million, \$79.6 million and \$78.5 million for 2014, 2013 and 2012, respectively. These expenses include capacity payments for PPAs accounted for as operating leases of \$61.0 million, \$59.1 million and \$59.0 million in 2014, 2013 and 2012, respectively, recorded to electric fuel and purchased power expenses.

Included in the future commitments under operating leases are estimated future capacity payments under PPAs that have been accounted for as operating leases in accordance with the applicable accounting guidance. Future commitments under all operating leases are:

(Millions of Dollars)	Operating Leases	PPA ^{(a) (b)} Operating Leases	Total Operating Leases
2015	\$ 7.2	\$ 62.5	\$ 69.7
2016	7.3	63.5	70.8
2017	7.8	64.5	72.3
2018	7.5	65.6	73.1
2019	12.1	66.7	78.8
Thereafter	70.5	425.3	495.8

(a) Amounts do not include PPAs accounted for as executory contracts.

(b) PPA operating leases contractually expire through 2026.

Variable Interest Entities — The accounting guidance for consolidation of variable interest entities requires enterprises to consider the activities that most significantly impact an entity’s financial performance, and power to direct those activities, when determining whether an enterprise is a variable interest entity’s primary beneficiary.

PPAs — Under certain PPAs, NSP-Minnesota purchases power from independent power producing entities that own natural gas or biomass fueled power plants for which NSP-Minnesota is required to reimburse natural gas or biomass fuel costs, or to participate in tolling arrangements under which NSP-Minnesota procures the natural gas required to produce the energy that it purchases. These specific PPAs create a variable interest in the associated independent power producing entity.

NSP-Minnesota has determined that certain independent power producing entities are variable interest entities. NSP-Minnesota is not subject to risk of loss from the operations of these entities, and no significant financial support has been, or is in the future, required to be provided other than contractual payments for energy and capacity set forth in the PPAs.

NSP-Minnesota has evaluated each of these variable interest entities for possible consolidation, including review of qualitative factors such as the length and terms of the contract, control over O&M, control over dispatch of electricity, historical and estimated future fuel and electricity prices, and financing activities. NSP-Minnesota has concluded that these entities are not required to be consolidated in its consolidated financial statements because it does not have the power to direct the activities that most significantly impact the entities’ economic performance. NSP-Minnesota had approximately 1,069 MW of capacity under long-term PPAs as of Dec. 31, 2014 and 2013 with entities that have been determined to be variable interest entities. These agreements have expiration dates through the year 2028.

Guarantees — Under NSP-Minnesota’s railcar lease agreement, accounted for as an operating lease, NSP-Minnesota guarantees the lessor proceeds from sale of the leased assets at the end of the lease term will at least equal the guaranteed residual value. The guarantee issued by NSP-Minnesota limits its exposure to a maximum amount stated in the guarantee; however, NSP-Minnesota expects sale proceeds to exceed the guaranteed amount.

The following table presents the guarantee issued and outstanding for NSP-Minnesota:

	Guarantee Amount	Current Exposure	Term or Expiration Date	Triggering Event
Guarantee of residual value of assets under the Bank of Tokyo-Mitsubishi Capital Corporation Equipment Leasing Agreement	\$ 4.8	\$ —	2019	(a)

(a) Actual fair value of leased assets is less than the guaranteed residual value amount at the end of the lease term.

Environmental Contingencies

NSP-Minnesota has been or is currently involved with the cleanup of contamination from certain hazardous substances at several sites. In many situations, NSP-Minnesota believes it will recover some portion of these costs through insurance claims. Additionally, where applicable, NSP-Minnesota is pursuing, or intends to pursue, recovery from other PRPs and through the regulated rate process. New and changing federal and state environmental mandates can also create added financial liabilities for NSP-Minnesota, which are normally recovered through the regulated rate process. To the extent any costs are not recovered through the options listed above, NSP-Minnesota would be required to recognize an expense.

Site Remediation — Various federal and state environmental laws impose liability, without regard to the legality of the original conduct, where hazardous substances or other regulated materials have been released to the environment. NSP-Minnesota may sometimes pay all or a portion of the cost to remediate sites where past activities of NSP-Minnesota or other parties have caused environmental contamination. Environmental contingencies could arise from various situations, including sites of former MGPs operated by NSP-Minnesota, its predecessors, or other entities; and third-party sites, such as landfills, for which NSP-Minnesota is alleged to be a PRP that sent hazardous materials and wastes to that site.

MGP Sites — NSP-Minnesota is currently involved in investigating and/or remediating several MGP sites where hazardous or other regulated materials may have been deposited. NSP-Minnesota has identified four sites where former MGP activities have or may have resulted in site contamination and are under current investigation and/or remediation. At some or all of these MGP sites, there are other parties that may have responsibility for some portion of any remediation. NSP-Minnesota anticipates that the majority of the remediation at these sites will continue through at least 2015. NSP-Minnesota had accrued \$0.1 million for all of these sites at Dec. 31, 2014 and an immaterial amount at Dec. 31, 2013. There may be insurance recovery and/or recovery from other PRPs that will offset any costs incurred. NSP-Minnesota anticipates that any amounts spent will be fully recovered from customers.

Environmental Requirements

Water and Waste

Asbestos Removal — Some of NSP-Minnesota's facilities contain asbestos. Most asbestos will remain undisturbed until the facilities that contain it are demolished or removed. NSP-Minnesota has recorded an estimate for final removal of the asbestos as an ARO. It may be necessary to remove some asbestos to perform maintenance or make improvements to other equipment. The cost of removing asbestos as part of other work is not expected to be material and is recorded as incurred as operating expenses for maintenance projects, capital expenditures for construction projects or removal costs for demolition projects.

Federal Clean Water Act (CWA) Effluent Limitations Guidelines (ELG) — In June 2013, the EPA published a proposed ELG rule for power plants that use coal, natural gas, oil or nuclear materials as fuel and discharge treated effluent to surface waters as well as utility-owned landfills that receive coal combustion residuals. The final rule is now expected in September 2015. Under the current proposed rule, facilities would need to comply as soon as possible after July 2017, but no later than July 2022. The impact of this rule on NSP-Minnesota is uncertain at this time.

Federal CWA Section 316(b) — Section 316(b) of the federal CWA requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available for minimizing adverse environmental impacts to aquatic species. The EPA published the final 316(b) rule in August 2014. The rule prescribes technology for protecting fish that get stuck on plant intake screens (known as impingement) and describes a process for site-specific determinations by each state for sites that must protect the small aquatic organisms that pass through the intake screens into the plant cooling systems (known as entrainment). The timing of compliance with the requirements will vary from plant-to-plant since the new rule does not have a final compliance deadline. NSP-Minnesota estimates the likely cost for complying with impingement requirements is approximately \$42 million. NSP-Minnesota believes at least three plants could be required by state regulators to make improvements to reduce entrainment. The exact cost of the entrainment improvements is uncertain, but could be up to \$145 million depending on the outcome of certain entrainment studies and cost-benefit analyses. NSP-Minnesota anticipates these costs will be fully recoverable in rates.

Federal CWA Waters of the United States Rule — In April 2014, the EPA and the U.S. Army Corps of Engineers issued a proposed rule that significantly expands the types of water bodies regulated under the CWA. If finalized as proposed, this rule could delay the siting of new pipelines, transmission lines and distribution lines, increase project costs and expand permitting and reporting requirements. The ultimate impact of the proposed rule will depend on the specific requirements of the final rule and cannot be determined at this time. A final rule is not anticipated before the second quarter of 2015.

Coal Ash Regulation — NSP-Minnesota’s operations are subject to federal and state laws that impose requirements for handling, storage, treatment and disposal of solid waste. In 2010, the EPA published a proposed rule on the regulation of coal combustion byproducts (coal ash) as hazardous or nonhazardous waste. The EPA issued a pre-publication version of the final rule in December 2014, which once promulgated will impose new rules to regulate coal ash as a nonhazardous solid waste. NSP-Minnesota’s costs for the management and disposal of coal ash will not significantly increase under the new rule.

Air

GHG Emission Standard for Existing Sources — In June 2014, the EPA published its proposed rule on GHG emission standards for existing power plants. Comments were due to the EPA on Dec. 1, 2014 and a final rule is anticipated in mid-summer 2015. Following adoption of the final rule, states must develop implementation plans by June 2016, with the possibility of an extension to June 2017 (June 2018 if submitting a joint plan with other states). Among other things, the proposed rule would require that state plans include enforceable measures to ensure emissions from existing power plants in the state achieve the EPA’s state-specific interim (2020-2029) and final (2030 and thereafter) emission performance targets. The plan will likely require additional emission reductions in states in which NSP-Minnesota operates. It is not possible to evaluate the impact of existing source standards until the EPA promulgates a final rule and states have adopted their applicable state plans.

GHG NSPS Proposal — In January 2014, the EPA re-proposed a GHG NSPS for newly constructed power plants which would set performance standards (maximum carbon dioxide emission rates) for coal- and natural gas-fired power plants. For coal power plants, the NSPS requires an emissions level equivalent to partial carbon capture and storage (CCS) technology; for gas-fired power plants, the NSPS reflects emissions levels from combined cycle technology with no CCS. The EPA continues to propose that the NSPS not apply to modified or reconstructed existing power plants. In addition, installation of control equipment on existing plants would not constitute a “modification” to those plants under the NSPS program. A final rule is anticipated in mid-summer 2015. It is not possible to evaluate the impact of the re-proposed NSPS until its final requirements are known.

GHG NSPS for Modified and Reconstructed Power Plants — In June 2014, the EPA published a proposed NSPS that would apply to GHG emissions from power plants that are modified or reconstructed. A final rule is anticipated in mid-summer 2015. A modification is a change to an existing source that increases the maximum achievable hourly rate of emissions. A reconstruction involves the replacement of components at a unit to the extent that the capital cost of the new components exceeds 50 percent of the capital cost of an entirely new comparable unit. The proposed standards would not require installation of CCS technology. Instead, the proposed standard for coal-fired power plants would require a combination of best operating practices and equipment upgrades. The proposal for gas-fired power plants would require emissions standards based on efficient combined cycle technology. It is not possible to evaluate the impact of these proposed standards until the final requirements are known. In addition, it is not clear whether these requirements, once adopted, would apply to future changes at NSP-Minnesota’s power plants.

CSAPR — CSAPR addresses long range transport of PM and ozone by requiring reductions in SO₂ and NO_x from utilities in the eastern half of the United States, including Minnesota, using an emissions trading program.

In August 2012, the D.C. Circuit vacated the CSAPR and remanded it back to the EPA. The D.C. Circuit stated the EPA must continue administering CSAPR’s predecessor rule pending adoption of a valid replacement. In April 2014, the U.S. Supreme Court reversed and remanded the case to the D.C. Circuit. The Supreme Court held that the EPA’s rule design did not violate the CAA and that states had received adequate opportunity to develop their own plans. Because the D.C. Circuit overturned the CSAPR on two over-arching issues, there are many other issues the D.C. Circuit did not rule on that will now need to be considered on remand. In October 2014, the D.C. Circuit granted the EPA’s request to begin to implement CSAPR by imposing its 2012 compliance obligations starting in January 2015. In addition, the D.C. Circuit set a briefing schedule and plans to hear arguments on the remaining issues in the case in February 2015. While the litigation continues, the EPA will begin to administer the CSAPR in 2015.

NSP-Minnesota can operate within its CSAPR emission allowance allocations, particularly given the cessation of coal operations at Black Dog Units 3 and 4 before mid-April 2015. CSAPR compliance in 2015 is not expected to have a material impact on the results of operations, financial position or cash flows.

EGU Mercury and Air Toxics Standards (MATS) Rule — The final EGU MATS rule became effective in April 2012. The EGU MATS rule sets emission limits for acid gases, mercury and other hazardous air pollutants and requires coal-fired utility facilities greater than 25 MW to demonstrate compliance within three to four years of the effective date. NSP-Minnesota expects to comply with the EGU MATS rule through a combination of mercury and other emission control projects. In 2014, the U.S. Supreme Court decided to review the D.C. Circuit’s decision that upheld the MATS standard. It is not yet known what impact the Supreme Court’s decision may have on the MATS standard or its implementation schedule. NSP-Minnesota believes EGU MATS costs will be recoverable through regulatory mechanisms and does not expect a material impact on results of operations, financial position or cash flows.

Minnesota Mercury Legislation — NSP-Minnesota installed sorbent control systems at the Sherco Unit 3 and A.S. King generating plants and completed installation of mercury controls on Sherco Units 1 and 2. Installation costs through Dec. 31, 2014 were \$12.9 million for the mercury controls on the units and NSP-Minnesota believes these costs will be recoverable through regulatory mechanisms.

Regional Haze Rules — The regional haze program is designed to address widespread, regionally homogeneous haze that results from emissions from a multitude of sources. In 2005, the EPA amended the BART requirements of its regional haze rules, which require the installation and operation of emission controls for industrial facilities emitting air pollutants that reduce visibility in certain national parks and wilderness areas. In its first regional haze SIP, Minnesota identified the NSP-Minnesota facilities that will have to reduce SO₂, NO_x and PM emissions under BART and set emissions limits for those facilities.

In 2009, the MPCA approved a SIP and submitted it to the EPA for approval. The MPCA’s source-specific BART limits for Sherco Units 1 and 2 require combustion controls for NO_x and scrubber upgrades for SO₂. The MPCA concluded SCRs should not be required because the minor visibility benefits derived from SCRs do not outweigh the substantial costs. The combustion controls were installed first and the scrubber upgrades were completed in December 2014. These emission controls cost \$46.6 million. NSP-Minnesota anticipates these costs will be fully recoverable in rates.

After the CSAPR was adopted in 2011, the MPCA supplemented its SIP, determining that CSAPR meets BART requirements, but also implementing its source-specific BART determination for Sherco Units 1 and 2 from the 2009 SIP. In June 2012, the EPA approved the SIP for EGUs and also approved the source-specific emission limits for Sherco Units 1 and 2 as strengthening the SIP, but avoided characterizing them as BART limits.

In August 2012, the National Parks Conservation Association, Sierra Club, Voyageurs National Park Association, Friends of the Boundary Waters Wilderness, Minnesota Center for Environmental Advocacy and Fresh Energy appealed the EPA’s approval of the SIP to the U.S. Court of Appeals for the Eighth Circuit (Eighth Circuit). NSP-Minnesota and other regulated parties were denied intervention. In June 2013, the Eighth Circuit ordered this case to be held in abeyance until the U.S. Supreme Court decided the CSAPR case. In October 2014, the Eighth Circuit set a briefing schedule that will be completed in early 2015. An argument date has not been set. If this litigation ultimately results in further EPA proceedings concerning the SIP, such proceedings may consider whether SCRs should be required for Sherco Units 1 and 2.

Reasonably Attributable Visibility Impairment (RAVI) — RAVI is intended to address observable impairment from a specific source such as distinct, identifiable plumes from a source’s stack to a national park. In 2009, the DOI certified that a portion of the visibility impairment in Voyageurs and Isle Royale National Parks is reasonably attributable to emissions from Sherco Units 1 and 2. The EPA is required to make its own determination whether there is RAVI-type impairment in these parks and examine which sources may cause or contribute to any RAVI impact that is identified. After studying the national parks and evaluating multiple sources, if the EPA finds that Sherco Units 1 and 2 cause or contribute to RAVI in the national parks, the EPA would then evaluate whether the level of controls required by the MPCA is appropriate. The EPA has stated it plans to issue a separate notice on the issue of BART for Sherco Units 1 and 2 under the RAVI program.

In December 2012, a lawsuit against the EPA was filed in the U.S. District Court for the District of Minnesota by the following organizations: National Parks Conservation Association, Minnesota Center for Environmental Advocacy, Friends of the Boundary Waters Wilderness, Voyageurs National Park Association, Fresh Energy and Sierra Club. The lawsuit alleges the EPA has failed to perform a nondiscretionary duty to determine BART for Sherco Units 1 and 2 under the RAVI program. The EPA filed an answer denying the allegations. The District Court denied NSP-Minnesota’s motion to intervene in July 2013. NSP-Minnesota appealed this decision to the Eighth Circuit, which on July 23, 2014, reversed the District Court and found that NSP-Minnesota has standing and a right to intervene.

In June 2014, the EPA and the plaintiffs lodged a consent decree with the District Court. The public comment period on the draft consent decree has been completed. The EPA is evaluating comments and will determine whether to enter the consent decree with the District Court. The draft consent decree would establish a schedule whereby the EPA would issue a proposal on Feb. 27, 2015, or 30 days after the District Court enters the consent decree if the decree is entered after Feb. 27, 2015. The proposal would provide the EPA's analysis of whether visibility impairment in the national parks is reasonably attributable to Sherco Units 1 and 2. If the EPA determines that it is, the draft consent decree requires the EPA to make a final RAVI BART determination for these units by Aug. 31, 2015. If the EPA determines that it is not, the EPA would not determine BART for Sherco Units 1 and 2. NSP-Minnesota filed comments opposing the proposed consent decree and will object to its entry given NSP-Minnesota's right to intervene in the litigation and thus participate in the negotiation of any purported settlement of the case.

Revisions to the National Ambient Air Quality Standards (NAAQS) for PM — In December 2012, the EPA lowered the primary health-based NAAQS for annual average fine PM and retained the current daily standard for fine PM. In areas where NSP-Minnesota operates power plants, current monitored air concentrations are below the level of the final annual primary standard. In December 2014, the EPA issued its final designations, which did not include areas in any states in which NSP-Minnesota operates.

Revisions to the NAAQS for Ozone — In December 2014, the EPA proposed to revise the NAAQS for ozone by lowering the eight-hour standard from 0.075 parts per million (ppm) to a level within the range of 0.065-0.070 ppm. The EPA is also taking comment on a level for the standard as low as 0.060 ppm. In areas where NSP-Minnesota operates, current monitored air quality concentrations are above the proposed level of 0.065 ppm in the Twin Cities Metropolitan Area in Minnesota. The EPA is expected to adopt a new ozone standard in a final rule to be issued in October 2015. Depending on the level of the standard, impacted states would study the sources of the nonattainment and make emission reduction plans to attain the standards. These plans would be due to the EPA in 2020 or 2021. Such plans could include installation of further NOx controls on power plants. It is not possible to evaluate the impact of this proposal until the final standard is adopted, the designation of nonattainment areas is made in late 2017 based on air quality data years 2014-2016, and any required state plans are developed.

NOV — In 2011, NSP-Minnesota received an NOV from the EPA alleging violations of the New Source Review (NSR) requirements of the CAA at the Sherco plant and Black Dog plant in Minnesota. The NOV alleges that various maintenance, repair and replacement projects at the plants in the mid 2000s should have required a permit under the NSR process. NSP-Minnesota believes it has acted in full compliance with the CAA and NSR process. NSP-Minnesota also believes that the projects identified in the NOV fit within the routine maintenance, repair and replacement exemption contained within the NSR regulations or are otherwise not subject to the NSR requirements. NSP-Minnesota disagrees with the assertions contained in the NOV and intends to vigorously defend its position. It is not known whether any costs would be incurred as a result of this NOV.

Asset Retirement Obligations

Recorded AROs — AROs have been recorded for property related to the following: electric production (nuclear, steam, wind, other and hydro), electric distribution and transmission, natural gas transmission and distribution, and general property. The electric production obligations include asbestos, ash-containment facilities, radiation sources, storage tanks, control panels and decommissioning. The asbestos recognition associated with the electric production includes certain plants. NSP-Minnesota also recorded asbestos recognition for its general office building. This asbestos abatement removal obligation originated in 1973 with the CAA, which applied to the demolition of buildings or removal of equipment containing asbestos that can become airborne on removal. AROs also have been recorded for NSP-Minnesota steam production related to ash-containment facilities such as bottom ash ponds, evaporation ponds and solid waste landfills. The origination dates on the ARO recognition for ash-containment facilities at steam plants were the in-service dates of the various facilities. NSP-Minnesota has also recorded AROs for the retirement and removal of assets at certain wind production facilities for which the land is leased and removal is required by contract, with the origination dates being the in-service date of the various facilities.

NSP-Minnesota has recognized an ARO for the retirement costs of natural gas mains and lines and for the removal of electric transmission and distribution equipment, which consists of many small potential obligations associated with PCBs, mineral oil, storage tanks, treated poles, lithium batteries, mercury and street lighting lamps. The electric and common general AROs include small obligations related to storage tanks, radiation sources and office buildings. These assets have numerous in-service dates for which it is difficult to assign the obligation to a particular year. Therefore, the obligation was measured using an average service life.

In December 2014, the EPA issued a pre-publication version of a final rule imposing requirements for activities involving coal ash waste. The ruling, once effective, will not result in the creation of a new legal obligation and NSP-Minnesota's estimated cash flows for the closure of coal ash landfills and impoundments are not expected to significantly increase as a result of the ruling.

For the nuclear assets, the ARO associated with the decommissioning of the NSP-Minnesota nuclear generating plants, Monticello and PI, originated with the in-service date of the facility. See Note 12 for further discussion of nuclear obligations.

A reconciliation of NSP-Minnesota's AROs for the years ended Dec. 31, 2014 and 2013 is as follows:

(Thousands of Dollars)	Beginning Balance Jan. 1, 2014	Liabilities Recognized	Accretion	Cash Flow Revisions	Ending Balance Dec. 31, 2014 ^(a)
Electric plant					
Nuclear production decommissioning	\$ 1,628,298	\$ —	\$ 86,284	\$ 323,365	\$ 2,037,947
Steam and other production ash containment	48,947	—	1,393	13,390	63,730
Steam and other production asbestos	13,303	—	536	—	13,839
Wind production	34,511	—	1,654	—	36,165
Electric distribution	4,871	—	177	—	5,048
Other	1,390	456	54	3	1,903
Natural gas plant					
Gas transmission and distribution	333	2,281	22	23,726	26,362
Common and other property					
Common general plant asbestos	480	—	25	—	505
Common miscellaneous	630	—	23	22	675
Total liability	<u>\$ 1,732,763</u>	<u>\$ 2,737</u>	<u>\$ 90,168</u>	<u>\$ 360,506</u>	<u>\$ 2,186,174</u>

^(a) There were no ARO liabilities settled during the year ended Dec. 31, 2014.

The aggregate fair value of NSP-Minnesota's legally restricted assets, for purposes of funding future nuclear decommissioning, was \$1.7 billion as of Dec. 31, 2014, consisting of external investment funds.

(Thousands of Dollars)	Beginning Balance Jan. 1, 2013	Accretion	Cash Flow Revisions	Ending Balance Dec. 31, 2013 ^(a)
Electric plant				
Nuclear production decommissioning	\$ 1,546,358	\$ 81,940	\$ —	\$ 1,628,298
Steam and other production ash containment	47,926	1,361	(340)	48,947
Steam and other production asbestos	12,789	514	—	13,303
Wind production	32,936	1,575	—	34,511
Electric distribution	12,443	358	(7,930)	4,871
Other	1,137	118	135	1,390
Natural gas plant				
Gas transmission and distribution	339	23	(29)	333
Common and other property				
Common general plant asbestos	1,197	66	(783)	480
Common miscellaneous	277	27	326	630
Total liability	<u>\$ 1,655,402</u>	<u>\$ 85,982</u>	<u>\$ (8,621)</u>	<u>\$ 1,732,763</u>

^(a) There were no new ARO liabilities recognized or settled during the year ended Dec. 31, 2013.

The aggregate fair value of NSP-Minnesota's legally restricted assets, for purposes of funding future nuclear decommissioning, was \$1.6 billion as of Dec. 31, 2013, consisting of external investment funds.

Removal Costs — NSP-Minnesota records a regulatory liability for the plant removal costs of generation, transmission and distribution facilities that are recovered currently in rates. Generally, the accrual of future non-ARO removal obligations is not required. However, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates. These removal costs have accumulated over a number of years based on varying rates as authorized by the appropriate regulatory entities. Given the long time periods over which the amounts were accrued and the changing of rates over time, NSP-Minnesota has estimated the amount of removal costs accumulated through historic depreciation expense based on current factors used in the existing depreciation rates. Removal costs as of Dec. 31, 2014 and 2013 were \$396 million and \$378 million, respectively.

Nuclear Insurance

NSP-Minnesota's public liability for claims resulting from any nuclear incident is limited to \$13.6 billion under the Price-Anderson amendment to the Atomic Energy Act. NSP-Minnesota has secured \$375 million of coverage for its public liability exposure with a pool of insurance companies. The remaining \$13.2 billion of exposure is funded by the Secondary Financial Protection Program, available from assessments by the federal government in case of a nuclear accident. NSP-Minnesota is subject to assessments of up to \$127.3 million per reactor per accident for each of its three licensed reactors, to be applied for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is \$19.0 million per reactor during any one year. These maximum assessment amounts are both subject to inflation adjustment by the NRC and state premium taxes. The NRC's last adjustment was effective September 2013.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Ltd. (NEIL). The coverage limits are \$2.3 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage, including the cost of replacement power obtained during certain prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term. All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage. However, in each calendar year, NSP-Minnesota could be subject to maximum assessments of approximately \$17.9 million for business interruption insurance and \$43.6 million for property damage insurance if losses exceed accumulated reserve funds.

Legal Contingencies

NSP-Minnesota is involved in various litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on NSP-Minnesota's financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Employment, Tort and Commercial Litigation

Biomass Fuel Handling Reimbursement — NSP-Minnesota has a PPA through which it procures energy from Fibrominn, LLC (Fibrominn). Under this agreement, NSP-Minnesota is charged for certain costs of transporting biomass fuels that are delivered to Fibrominn's generation facility. Fibrominn has demanded additional cost reimbursement for certain transportation costs incurred since 2007, as well as reimbursement for similar costs in future periods. Fibrominn claims that it is entitled to reimbursement from NSP-Minnesota for past transportation costs of approximately \$20 million. NSP-Minnesota has evaluated Fibrominn's claim and based on the terms of the PPA with Fibrominn and its current understanding of the facts, NSP-Minnesota disputes the validity of Fibrominn's claim, on the ground that, among other things, it seeks to impose contractual obligations on NSP-Minnesota that are neither supported by the terms nor the intent of the PPA. NSP-Minnesota has concluded that a loss is reasonably possible with respect to this matter; however, given the surrounding uncertainties, NSP-Minnesota is currently unable to determine the amount of reasonably possible loss. If a loss were sustained, NSP-Minnesota would attempt to recover these fuel-related costs in rates. No accrual has been recorded for this matter.

Nuclear Power Operations and Waste Disposal

Nuclear Waste Disposal Litigation — In 1998, NSP-Minnesota filed a complaint in the U.S. Court of Federal Claims against the United States requesting breach of contract damages for the DOE’s failure to begin accepting spent nuclear fuel by Jan. 31, 1998, as required by the contract between the United States and NSP-Minnesota. NSP-Minnesota sought contract damages in this lawsuit through Dec. 31, 2004. In September 2007, the Court awarded NSP-Minnesota \$116.5 million in damages. In August 2007, NSP-Minnesota filed a second complaint; this lawsuit claimed damages for the period Jan. 1, 2005 through Dec. 31, 2008.

In July 2011, the United States and NSP-Minnesota executed a settlement agreement resolving both lawsuits, providing an initial \$100 million payment from the United States to NSP-Minnesota, and providing a method by which NSP-Minnesota can recover its spent fuel storage costs through 2013, estimated to be an additional \$100 million. In January 2014, the United States proposed, and NSP-Minnesota accepted, an extension to the settlement agreement which will allow NSP-Minnesota to recover spent fuel storage costs through 2016. The extension does not address costs for used fuel storage after 2016; such costs could be the subject of future litigation. In December 2014, NSP-Minnesota received a settlement payment of \$32.8 million. NSP-Minnesota has received a total of \$214.7 million of settlement proceeds as of Dec. 31, 2014. Amounts received from the installments, except for approved reductions such as legal costs, will be subsequently returned to customers through a reduction of future rate increases or credited through another regulatory mechanism.

Other Contingencies

See Note 10 for further discussion.

12. Nuclear Obligations

Fuel Disposal — NSP-Minnesota is responsible for temporarily storing used or spent nuclear fuel from its nuclear plants. The DOE is responsible for permanently storing spent fuel from NSP-Minnesota’s nuclear plants as well as from other U.S. nuclear plants, but no such facility is yet available. NSP-Minnesota has funded its portion of the DOE’s permanent disposal program since 1981. The fuel disposal fees were based on a charge of 0.1 cent per KWh sold to customers from nuclear generation. Effective May 2014, the DOE set the fee to zero.

Fuel expense includes the DOE fuel disposal assessments of approximately \$5 million in 2014, \$10 million in 2013 and \$12 million in 2012. In total, NSP-Minnesota paid approximately \$452.1 million to the DOE through Dec. 31, 2014. See Note 11 — Nuclear Waste Disposal Litigation for further discussion.

NSP-Minnesota has its own temporary on-site storage facilities for spent fuel at its Monticello and PI nuclear plants, which consist of storage pools and dry cask facilities at both sites. The amount of spent fuel storage capacity is determined by the NRC and the MPUC. The Monticello dry-cask storage facility currently stores 15 of the 30 authorized canisters, and the PI dry-cask storage facility currently stores 38 of the 64 authorized casks. Other alternatives for spent fuel storage are being investigated until a DOE facility is available.

Regulatory Plant Decommissioning Recovery — Decommissioning activities related to NSP-Minnesota’s nuclear facilities are planned to begin at the end of each unit’s operating license and be completed by 2091. NSP-Minnesota’s current operating licenses allow continued use of its Monticello nuclear plant until 2030 and its PI nuclear plant until 2033 for Unit 1 and 2034 for Unit 2.

Future decommissioning costs of nuclear facilities are estimated through periodic studies that assess the costs and timing of planned nuclear decommissioning activities for each unit. The MPUC most recently approved NSP-Minnesota’s 2011 nuclear decommissioning study in November 2012. This cost study quantified decommissioning costs in 2011 dollars and utilized escalation rates of 3.63 percent per year for plant removal activities, and 2.63 percent for spent fuel management and site restoration activities over a 60-year decommissioning scenario.

In December 2014, NSP-Minnesota submitted its most recent nuclear decommissioning filing to the MPUC, which included an update to the decommissioning cost study and requested an annual funding requirement of \$14.0 million starting in 2016. A decision on the filing is expected in late 2015 or early 2016.

The total obligation for decommissioning is expected to be funded 100 percent by the external decommissioning trust fund when decommissioning commences. NSP-Minnesota's most recently approved decommissioning study resulted in an annual funding requirement of \$14.2 million to be recovered in utility customer rates. This cost study assumes the external decommissioning fund will earn an after-tax return between 4.57 percent and 5.53 percent. Realized and unrealized gains on fund investments are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs.

As of Dec. 31, 2014, NSP-Minnesota has accumulated \$1.7 billion of assets held in external decommissioning trusts. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation based on parameters established in the most recently approved decommissioning study. Xcel Energy believes future decommissioning costs, if necessary, will continue to be recovered in customer rates. The amounts presented below were prepared on a regulatory basis, and are not recorded in the financial statements for the ARO.

(Thousands of Dollars)	Regulatory Basis	
	2014	2013
Estimated decommissioning cost obligation from most recently approved study (2011 dollars)	\$ 2,694,079	\$ 2,694,079
Effect of escalating costs (to 2014 and 2013 dollars, respectively, at 3.63/2.63 percent)	289,907	189,924
Estimated decommissioning cost obligation (in current dollars)	2,983,986	2,884,003
Effect of escalating costs to payment date (3.63/2.63 percent)	5,597,302	5,697,285
Estimated future decommissioning costs (undiscounted)	8,581,288	8,581,288
Effect of discounting obligation (using average risk-free interest rate of 2.82 percent and 4.19 percent for 2014 and 2013, respectively)	(5,044,470)	(6,215,050)
Discounted decommissioning cost obligation	<u>\$ 3,536,818</u>	<u>\$ 2,366,238</u>
Assets held in external decommissioning trust	\$ 1,703,921	\$ 1,627,026
Underfunding of external decommissioning fund compared to the discounted decommissioning obligation	\$ 1,832,897	\$ 739,212

Decommissioning expenses recognized as a result of regulation include the following components:

(Thousands of Dollars)	2014	2013	2012
Annual decommissioning recorded as depreciation expense: ^(a)			
Externally funded	\$ 7,138	\$ 6,402	\$ —
Internally funded (including interest costs)	—	—	(1,251)
Net decommissioning expense recorded	<u>\$ 7,138</u>	<u>\$ 6,402</u>	<u>\$ (1,251)</u>

^(a) Decommissioning expense does not include depreciation of the capitalized nuclear asset retirement costs.

The reduction to expense for internally-funded portions in 2012 was a direct result of the 2008 decommissioning study jurisdictional allocation and 100 percent external funding approval, effectively unwinding the remaining internal fund over the previously licensed operating life of the unit (2010 for Monticello, 2013 for PI Unit 1 and 2014 for PI Unit 2). Due to the immaterial amount remaining in the internal fund, the entire remaining amount was unwound for PI 1 and 2 in 2012. As of Dec. 31, 2013, there was no balance remaining in the internally funded decommissioning account. The 2011 nuclear decommissioning filing approved in 2012 has been used for the regulatory presentation.

13. Regulatory Assets and Liabilities

NSP-Minnesota's consolidated financial statements are prepared in accordance with the applicable accounting guidance, as discussed in Note 1. Under this guidance, regulatory assets and liabilities are created for amounts that regulators may allow to be collected, or may require to be paid back to customers in future electric and natural gas rates. Any portion of the business that is not rate regulated cannot establish regulatory assets and liabilities. If changes in the utility industry or the business of NSP-Minnesota no longer allow for the application of regulatory accounting guidance under GAAP, NSP-Minnesota would be required to recognize the write-off of regulatory assets and liabilities in net income or OCI.

The components of regulatory assets shown on the consolidated balance sheets of NSP-Minnesota at Dec. 31, 2014 and 2013 are:

(Thousands of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2014		Dec. 31, 2013	
			Current	Noncurrent	Current	Noncurrent
Regulatory Assets						
Pension and retiree medical obligations ^(a)	7	Various	\$ 22,357	\$ 353,845	\$ 29,381	\$ 286,088
Recoverable deferred taxes on AFUDC recorded in plant	1	Plant lives	—	200,525	—	198,698
Net AROs ^(c)	1, 11, 12	Plant lives	—	120,020	—	98,419
Contract valuation adjustments ^(b)	1, 9	Term of related contract	8,358	131,274	—	136,919
Conservation programs ^(d)	1	One to two years	48,217	42,247	38,850	36,092
Nuclear refueling outage costs	1	One to two years	62,499	19,745	86,333	36,477
Renewable resources and environmental initiatives	11	One to two years	18,166	24,779	20,323	20,187
Purchased power contracts costs	11	Term of related contract	—	40,312	—	38,113
Losses on reacquired debt	4	Term of related debt	1,928	15,368	1,928	17,296
Recoverable purchased natural gas and electric energy costs	1	One to two years	42,972	4,745	23,101	15,495
Gas pipeline inspection and remediation costs		Pending rate case	4,564	18,258	—	18,907
State commission adjustments	1	Plant lives	—	4,150	—	4,278
PI EPU ^(e)	10	Pending rate cases	8,743	62,141	—	69,668
Other		Various	17,683	14,425	7,551	13,567
Total regulatory assets			\$ 235,487	\$1,051,834	\$ 207,467	\$ 990,204

(a) Includes \$282.4 million and \$303.3 million for the regulatory recognition of pension expense of which \$23.8 million and \$23.2 million is included in the current asset at Dec. 31, 2014 and 2013, respectively. Also included are \$2.9 million and \$2.3 million of regulatory assets related to the non-qualified pension plan of which \$0.3 million is included in the current asset at Dec. 31, 2014 and 2013.

(b) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.

(c) Includes amounts recorded for future recovery of AROs, less amounts recovered through nuclear decommissioning accruals and gains from decommissioning investments.

(d) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.

(e) For the canceled PI EPU project, NSP-Minnesota has addressed recovery of incurred costs in the pending multi-year rate case.

The components of regulatory liabilities shown on the consolidated balance sheets of NSP-Minnesota at Dec. 31, 2014 and 2013 are:

(Thousands of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2014		Dec. 31, 2013	
			Current	Noncurrent	Current	Noncurrent
Regulatory Liabilities						
Plant removal costs	1, 11	Plant lives	\$ —	\$ 396,091	\$ —	\$ 377,716
DOE Settlement	11	One to two years	44,561	—	37,395	1,131
Deferred income tax adjustment	1, 6	Various	—	28,262	—	28,100
Conservation programs ^(b)	1	Less than one year	68,690	—	4,690	—
Investment tax credit deferrals	1, 6	Various	—	20,614	—	21,898
Contract valuation adjustments ^(a)	1, 9	Term of related contract	35,540	—	39,632	—
Deferred electric energy costs	1	Less than one year	10,521	—	6,390	—
Renewable resources and environmental initiatives	10, 11	Less than one year	7,119	—	2,499	—
Other		Various	5,177	6,816	11,189	2,154
Total regulatory liabilities			\$ 171,608	\$ 451,783	\$ 101,795	\$ 430,999

(a) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.

(b) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.

At Dec. 31, 2014 and 2013, approximately \$154 million and \$140 million of NSP-Minnesota's regulatory assets represented past expenditures not currently earning a return, respectively. This amount primarily includes PI EPU costs and recoverable purchased natural gas and electric energy costs.

14. Other Comprehensive Income

Changes in accumulated other comprehensive (loss) income, net of tax, for the years ended Dec. 31, 2014 and 2013 were as follows:

(Thousands of Dollars)	Year Ended Dec. 31, 2014			
	Gains and Losses on Cash Flow Hedges	Unrealized Gains and Losses on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive (loss) income at Jan. 1	\$ (20,609)	\$ 73	\$ (1,193)	\$ (21,729)
Other comprehensive (loss) income before reclassifications	(89)	32	161	104
Losses reclassified from net accumulated other comprehensive loss	789	—	22	811
Net current period OCI	700	32	183	915
Accumulated other comprehensive (loss) income at Dec. 31	<u>\$ (19,909)</u>	<u>\$ 105</u>	<u>\$ (1,010)</u>	<u>\$ (20,814)</u>

(Thousands of Dollars)	Year Ended Dec. 31, 2013			
	Gains and Losses on Cash Flow Hedges	Unrealized Gains and Losses on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	\$ (21,393)	\$ (99)	\$ (1,707)	\$ (23,199)
OCI before reclassifications	5	172	423	600
Losses reclassified from net accumulated other comprehensive loss	779	—	91	870
Net current period OCI	784	172	514	1,470
Accumulated other comprehensive (loss) income at Dec. 31	<u>\$ (20,609)</u>	<u>\$ 73</u>	<u>\$ (1,193)</u>	<u>\$ (21,729)</u>

Reclassifications from accumulated other comprehensive loss for the years ended Dec. 31, 2014 and 2013 were as follows:

(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss	
	Year Ended Dec. 31, 2014	Year Ended Dec. 31, 2013
(Gains) losses on cash flow hedges:		
Interest rate derivatives	\$ 1,387 ^(a)	\$ 1,388 ^(a)
Vehicle fuel derivatives	(30) ^(b)	(49) ^(b)
Total, pre-tax	1,357	1,339
Tax benefit	(568)	(560)
Total, net of tax	789	779
Defined benefit pension and postretirement (gains) losses:		
Amortization of net loss	232 ^(c)	340 ^(c)
Prior service cost	(194) ^(c)	(188) ^(c)
Transition obligation	— ^(c)	2 ^(c)
Total, pre-tax	38	154
Tax benefit	(16)	(63)
Total, net of tax	22	91
Total amounts reclassified, net of tax	<u>\$ 811</u>	<u>\$ 870</u>

(a) Included in interest charges.

(b) Included in O&M expenses.

(c) Included in the computation of net periodic pension and postretirement benefit costs. See Note 7 for details regarding these benefit plans.

15. Segments and Related Information

Operating results from the regulated electric utility and regulated natural gas utility are each separately and regularly reviewed by NSP-Minnesota's chief operating decision maker. NSP-Minnesota evaluates performance based on profit or loss generated from the product or service provided. These segments are managed separately because the revenue streams are dependent upon regulated rate recovery, which is separately determined for each segment.

NSP-Minnesota has the following reportable segments: regulated electric utility, regulated natural gas utility and all other.

- NSP-Minnesota's regulated electric utility segment generates electricity which is transmitted and distributed in Minnesota, North Dakota and South Dakota. In addition, this segment includes sales for resale and provides wholesale transmission service to various entities in the United States. Regulated electric utility also includes NSP-Minnesota's commodity trading operations.
- NSP-Minnesota's regulated natural gas utility segment transports, stores and distributes natural gas in portions of Minnesota and North Dakota.
- Revenues from operating segments not included above are below the necessary quantitative thresholds and are therefore included in the all other category. Those primarily include appliance repair services, nonutility real estate activities and revenues associated with processing solid waste into refuse-derived fuel.

Asset and capital expenditure information is not provided for NSP-Minnesota's reportable segments because as an integrated electric and natural gas utility, NSP-Minnesota operates significant assets that are not dedicated to a specific business segment, and reporting assets and capital expenditures by business segment would require arbitrary and potentially misleading allocations which may not necessarily reflect the assets that would be required for the operation of the business segments on a stand-alone basis.

To report income from operations for regulated electric and regulated natural gas utility segments, the majority of costs are directly assigned to each segment. However, some costs, such as common depreciation, common O&M expenses and interest expense are allocated based on cost causation allocators. A general allocator is used for certain general and administrative expenses, including office supplies, rent, property insurance and general advertising.

The accounting policies of the segments are the same as those described in Note 1.

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
2014					
Operating revenues ^(a)	\$ 4,202,357	\$ 757,695	\$ 28,473	\$ —	\$ 4,988,525
Intersegment revenues	938	828	—	(1,766)	—
Total revenues	<u>\$ 4,203,295</u>	<u>\$ 758,523</u>	<u>\$ 28,473</u>	<u>\$ (1,766)</u>	<u>\$ 4,988,525</u>
Depreciation and amortization	\$ 368,213	\$ 41,946	\$ 681	\$ —	\$ 410,840
Interest charges and financing costs	177,183	11,595	178	—	188,956
Income tax expense (benefit)	185,570	19,524	(7,004)	—	198,090
Net income	355,937	35,518	13,460	—	404,915
2013					
Operating revenues ^(a)	\$ 4,062,440	\$ 591,017	\$ 26,153	\$ —	\$ 4,679,610
Intersegment revenues	680	640	—	(1,320)	—
Total revenues	<u>\$ 4,063,120</u>	<u>\$ 591,657</u>	<u>\$ 26,153</u>	<u>\$ (1,320)</u>	<u>\$ 4,679,610</u>
Depreciation and amortization	\$ 373,747	\$ 40,163	\$ 678	\$ —	\$ 414,588
Interest charges and financing cost	162,084	11,572	154	—	173,810
Income tax expense (benefit)	183,854	17,416	(19,413)	—	181,857
Net income	338,900	29,891	24,555	—	393,346

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
2012					
Operating revenues ^(a)	\$ 3,842,529	\$ 471,765	\$ 23,045	\$ —	\$ 4,337,339
Intersegment revenues	532	608	—	(1,140)	—
Total revenues	<u>\$ 3,843,061</u>	<u>\$ 472,373</u>	<u>\$ 23,045</u>	<u>\$ (1,140)</u>	<u>\$ 4,337,339</u>
Depreciation and amortization	\$ 360,224	\$ 38,776	\$ 432	\$ —	\$ 399,432
Interest charges and financing cost	167,080	13,471	158	—	180,709
Income tax expense	161,450	9,516	4,558	—	175,524
Net income	314,853	17,389	7,899	—	340,141

(a) Operating revenues include \$475 million, \$459 million and \$450 million of intercompany revenue for the years ended Dec. 31, 2014, 2013 and 2012, respectively. See Note 16 for further discussion of related party transactions by operating segment.

16. Related Party Transactions

Xcel Energy Services Inc. provides management, administrative and other services for the subsidiaries of Xcel Energy Inc., including NSP-Minnesota. The services are provided and billed to each subsidiary in accordance with service agreements executed by each subsidiary. NSP-Minnesota uses the services provided by Xcel Energy Services Inc. whenever possible. Costs are charged directly to the subsidiary and are allocated if they cannot be directly assigned.

Xcel Energy Inc., NSP-Minnesota, PSCo and SPS have established a utility money pool arrangement. See Note 4 for further discussion.

The electric production and transmission costs of the entire NSP System are shared by NSP-Minnesota and NSP-Wisconsin. The Interchange Agreement provides for the sharing of all costs of generation and transmission facilities of the system, including capital costs.

The table below contains significant affiliate transactions among the companies and related parties including billings under the Interchange Agreement for the years ended Dec. 31:

(Thousands of Dollars)	2014	2013	2012
Operating revenues:			
Electric	\$ 474,542	\$ 458,633	\$ 449,958
Gas	96	97	116
Operating expenses:			
Purchased power	68,703	68,518	65,426
Transmission expense	76,399	68,398	59,918
Other operating expenses — paid to Xcel Energy Services Inc.	456,578	387,912	345,529
Interest expense	208	288	333
Interest income	28	22	18

Accounts receivable and payable with affiliates at Dec. 31 were:

(Thousands of Dollars)	2014		2013	
	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Wisconsin	\$ 17,333	\$ —	\$ 18,584	\$ —
PSCo	6,706	—	—	18,065
SPS	—	1,983	—	3,462
Other subsidiaries of Xcel Energy Inc.	28	48,562	1,185	44,414
	<u>\$ 24,067</u>	<u>\$ 50,545</u>	<u>\$ 19,769</u>	<u>\$ 65,941</u>

17. Summarized Quarterly Financial Data (Unaudited)

(Thousands of Dollars)	Quarter Ended			
	March 31, 2014	June 30, 2014	Sept. 30, 2014	Dec. 31, 2014
Operating revenues	\$ 1,424,326	\$ 1,124,759	\$ 1,190,213	\$ 1,249,227
Operating income	203,692	155,296	252,745	155,860
Net income	108,364	75,266	134,469	86,816

(Thousands of Dollars)	Quarter Ended			
	March 31, 2013	June 30, 2013	Sept. 30, 2013	Dec. 31, 2013
Operating revenues	\$ 1,193,235	\$ 1,084,845	\$ 1,217,476	\$ 1,183,638
Operating income	175,290	142,046	264,520	127,244
Net income	101,965	77,701	155,106	58,277

Item 9 — Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A — Controls and Procedures

Disclosure Controls and Procedures

NSP-Minnesota maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer (CEO) and chief financial officer (CFO), allowing timely decisions regarding required disclosure. As of Dec. 31, 2014, based on an evaluation carried out under the supervision and with the participation of NSP-Minnesota's management, including the CEO and CFO, of the effectiveness of its disclosure controls and the procedures, the CEO and CFO have concluded that NSP-Minnesota's disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

No change in NSP-Minnesota's internal control over financial reporting has occurred during the most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, NSP-Minnesota's internal control over financial reporting. NSP-Minnesota maintains internal control over financial reporting to provide reasonable assurance regarding the reliability of the financial reporting. NSP-Minnesota has evaluated and documented its controls in process activities, general computer activities, and on an entity-wide level. During the year and in preparation for issuing its report for the year ended Dec. 31, 2014 on internal controls under section 404 of the Sarbanes-Oxley Act of 2002, NSP-Minnesota conducted testing and monitoring of its internal control over financial reporting. Based on the control evaluation, testing and remediation performed, NSP-Minnesota did not identify any material control weaknesses, as defined under the standards and rules issued by the Public Company Accounting Oversight Board and as approved by the SEC and as indicated in Management Report on Internal Controls herein.

This annual report does not include an attestation report of NSP-Minnesota's independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by NSP-Minnesota's independent registered public accounting firm pursuant to the rules of the SEC that permit NSP-Minnesota to provide only management's report in this annual report.

Item 9B — Other Information

None.

PART III

Items 10, 11, 12 and 13 of Part III of Form 10-K have been omitted from this report for NSP-Minnesota in accordance with conditions set forth in general instructions I (1) (a) and (b) of Form 10-K for wholly-owned subsidiaries.

Item 10 — Directors, Executive Officers and Corporate Governance

Item 11 — Executive Compensation

Item 12 — Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Item 13 — Certain Relationships and Related Transactions, and Director Independence

Item 14 — Principal Accountant Fees and Services

Information required under this Item is contained in Xcel Energy Inc.'s Proxy Statement for its 2015 Annual Meeting of Shareholders, which is incorporate

PART IV

Item 15 — Exhibits, Financial Statement Schedules

1.	Consolidated Financial Statements:
	Management Report on Internal Controls Over Financial Reporting — For the year ended Dec. 31, 2014.
	Report of Independent Registered Public Accounting Firm — Financial Statements
	Consolidated Statements of Income — For the three years ended Dec. 31, 2014, 2013 and 2012.
	Consolidated Statements of Comprehensive Income — For the three years ended Dec. 31, 2014, 2013 and 2012.
	Consolidated Statements of Cash Flows — For the three years ended Dec. 31, 2014, 2013 and 2012.
	Consolidated Balance Sheets — As of Dec. 31, 2014 and 2013.
	Consolidated Statements of Common Stockholder's Equity — For the three years ended Dec. 31, 2014, 2013 and 2012.
	Consolidated Statements of Capitalization — As of Dec. 31, 2014 and 2013.
2.	Schedule II — Valuation and Qualifying Accounts and Reserves for the years ended Dec. 31, 2014, 2013 and 2012.
3.	Exhibits
*	Indicates incorporation by reference
+	Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors
3.01*	Articles of Incorporation and Amendments of Northern Power Corp. (renamed Northern States Power Co. (a Minnesota corporation) on Aug. 21, 2000) (Exhibit 3.01 to Form 10-12G (file no. 000-31709) dated Oct. 5, 2000).
3.02*	By-Laws of Northern States Power Co. (a Minnesota corporation) as Amended and Restated on Sept. 26, 2013 (Exhibit 3.02 to Form 10-Q/A for the quarter ended Sept. 30, 2013 (file no. 000-31387)).
4.01*	Supplemental and Restated Trust Indenture, dated May 1, 1988, from NSP-Minnesota to Harris Trust and Savings Bank, as Trustee, providing for the issuance of First Mortgage Bonds (Exhibit 4.02 to Form 10-K of NSP-Minnesota for the year ended Dec. 31, 1988 (file no. 001-03034)). Supplemental Indentures between NSP-Minnesota and said Trustee, dated as follows:
	Supplemental Trust Indenture dated June 1, 1995, creating \$250 million principal amount of 7.125 percent First Mortgage Bonds, Series due July 1, 2025 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated June 28, 1995).
	Supplemental Trust Indenture dated April 1, 1997, creating \$100 million principal amount of 8.5 percent First Mortgage Bonds, Series due Sept. 1, 2019 and \$27.9 million principal amount of 8.5 percent First Mortgage Bonds, Series due March 1, 2019 (Exhibit 4.47 to Form 10-K (file no. 001-03034) dated Dec. 31, 1997).
	Supplemental Trust Indenture dated March 1, 1998, creating \$150 million principal amount of 6.5 percent First Mortgage Bonds, Series due March 1, 2028 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated March 11, 1998).
4.02*	Supplemental Trust Indenture dated Aug. 1, 2000 (Assignment and Assumption of Trust Indenture) (Exhibit 4.51 to NSP-Minnesota Form 10-12G (file no. 000-31709) dated Oct. 5, 2000).
4.03*	Indenture, dated July 1, 1999, between NSP-Minnesota and Norwest Bank Minnesota, NA, as Trustee, providing for the issuance of Sr. Debt Securities. (Exhibit 4.01 to NSP-Minnesota Form 8-K (file no. 001-03034) dated July 21, 1999).
4.04*	Supplemental Indenture, dated Aug. 18, 2000, supplemental to the Indenture dated July 1, 1999, among Xcel Energy, NSP-Minnesota and Wells Fargo Bank Minnesota, NA, as Trustee (Assignment and Assumption of Indenture) (Exhibit 4.63 to NSP-Minnesota Form 10-12G (file no. 000-31709) dated Oct. 5, 2000).
4.05*	Supplemental Trust Indenture dated July 1, 2002 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating \$69 million principal amount of 8.5 percent First Mortgage Bonds, Series due April 1, 2030 (Exhibit 4.06 to NSP-Minnesota Quarterly Report on Form 10-Q (file no. 001-31387) dated Sept. 30, 2002).
4.06*	Supplemental Trust Indenture dated July 1, 2005 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating \$250 million principal amount of 5.25 percent First Mortgage Bonds, Series due July 15, 2035 (Exhibit 4.01 to NSP-Minnesota Current Report on Form 8-K (file no. 001-31387) dated July 14, 2005).
4.07*	Supplemental Trust Indenture dated May 1, 2006 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating \$400 million principal amount of 6.25 percent First Mortgage Bonds, Series due June 1, 2036 (Exhibit 4.01 to NSP-Minnesota Current Report on Form 8-K (file no. 001-31387) dated May 18, 2006).
4.08*	Supplemental Trust Indenture, dated June 1, 2007, between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee (Exhibit 4.01 to NSP-Minnesota Form 8-K (file no. 001-31387) dated June 19, 2007).

4.09*	Supplemental Trust Indenture dated March 1, 2008 between NSP-Minnesota and The Bank of New York Trust Company, NA, as successor Trustee (Exhibit 4.01 to NSP-Minnesota Form 8-K (file no. 001-31387) dated March 11, 2008).
4.10*	Supplemental Trust Indenture dated as of Nov. 1, 2009 between NSP-Minnesota and The Bank of New York Mellon Trust Co., NA, as successor Trustee, creating \$300 million principal amount of 5.35 percent First Mortgage Bonds, Series due Nov. 1, 2039 (Exhibit 4.01 to NSP-Minnesota Form 8-K (file no. 001-31387) dated Nov. 16, 2009).
4.11*	Supplemental Trust Indenture dated as of Aug. 1, 2010 between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA, as successor Trustee, creating \$250 million principal amount of 1.950 percent First Mortgage Bonds, Series due Aug. 15, 2015 and \$250 million principal amount of 4.850 percent First Mortgage Bonds, Series due Aug. 15, 2040 (Exhibit 4.01 to NSP-Minnesota Form 8-K dated Aug. 14, 2010 (file no. 001-31387)).
4.12*	Supplemental Trust Indenture dated as of Aug. 1, 2012 between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA, as successor Trustee, creating \$300 million principal amount of 2.15 percent First Mortgage Bonds, Series due Aug. 15, 2022 and \$500 million principal amount of 3.40 percent First Mortgage Bonds, Series due Aug. 15, 2042 (Exhibit 4.01 to NSP-Minnesota Form 8-K dated Aug. 13, 2012 (file no. 001-31387)).
4.13*	Supplemental Trust Indenture dated as of May 1, 2013 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating \$400 million principal amount of 2.60 percent First Mortgage Bonds, Series due May 15, 2023. (Exhibit 4.01 to NSP-Minnesota Form 8-K dated May 20, 2013 (file no. 001-31387))
4.14*	Supplemental Trust Indenture dated as of May 1, 2014 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating \$300 million principal amount of 4.125 percent First Mortgage Bonds, Series due May 15, 2044. (Exhibit 4.01 to NSP-Minnesota Form 8-K dated May 13, 2014 (file no. 001-31387)).
10.01**	Xcel Energy Inc. Nonqualified Pension Plan (2009 Restatement) (Exhibit 10.02 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
10.02**	Xcel Energy Senior Executive Severance and Change-in-Control Policy (2009 Amendment and Restatement) (Exhibit 10.05 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
10.03**	Xcel Energy Inc. Non-Employee Directors Deferred Compensation Plan (Exhibit 10.08 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
10.04**	Form of Services Agreement between Xcel Energy Services Inc. and utility companies (Exhibit H-1 to Form U5B (file no. 001-03034) dated Nov. 16, 2000).
10.05**	Xcel Energy Inc. Supplemental Executive Retirement Plan as amended and restated Jan. 1, 2009 (Exhibit 10.17 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
10.06*	Ownership and Operating Agreement, dated March 11, 1982, between NSP-Minnesota, Southern Minnesota Municipal Power Agency and United Minnesota Municipal Power Agency concerning Sherburne County Generating Unit No. 3 (Exhibit 10.01 to Form 10-Q for the quarter ended Sept. 30, 1994 (file no. 001-03034)).
10.07*	Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota (Exhibit 10.01 to NSP-Wisconsin Form S-4 (file no. 333-112033) dated Jan. 21, 2004).
10.08**	Amendment dated Aug. 26, 2009 to the Xcel Energy Senior Executive Severance and Change-in-Control Policy. (Exhibit 10.06 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended Sept. 30, 2009).
10.09**	Xcel Energy Executive Annual Incentive Award Plan Form of Restricted Stock Agreement (Exhibit 10.08 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended Sept. 30, 2009).
10.10**	Xcel Energy Inc. Executive Annual Incentive Award Plan (as amended and restated effective Feb. 17, 2010) (incorporated by reference to Appendix A to Schedule 14A, Definitive Proxy Statement to Xcel Energy (file no. 001-03034) dated April 6, 2010).
10.11**	Xcel Energy Inc. 2010 Executive Annual Discretionary Award Plan (Exhibit 10.24 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2009).
10.12**	Xcel Energy Inc. 2005 Long-Term Incentive Plan (as amended and restated effective Feb. 17, 2010) (incorporated by reference to Appendix B to Schedule 14A, Definitive Proxy Statement to Xcel Energy (file no. 001-03034) dated April 6, 2010).
10.13**	Xcel Energy Inc. 2010 Executive Annual Discretionary Award Plan (as amended and restated effective Dec. 15, 2010) (Exhibit 10.23 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2010).
10.14**	Xcel Energy Inc. 2005 Long-Term Incentive Plan Form of Bonus Stock Agreement (as amended and restated effective Feb. 17, 2010) (Exhibit 10.24 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2010).
10.15**	Xcel Energy Inc. 2005 Long-Term Incentive Plan Form of Performance Share Agreement (Exhibit 10.25 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2010).
10.16a**	Xcel Energy Inc. 2005 Long-Term Incentive Plan Form of Restricted Stock Unit Agreement (Exhibit 10.26 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2010).
10.16b**	Xcel Energy Inc. 2005 Long-Term Incentive Plan Form of Time-Based Restricted Stock Unit Agreement (Exhibit 10.14b to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2012).

10.17**+	Stock Equivalent Plan for Non-Employee Directors of Xcel Energy Inc. as amended and restated effective Feb. 23, 2011 (Appendix A to the Xcel Energy Definitive Proxy Statement (file no. 001-03034) filed Apr. 5, 2011).
10.18**+	Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement) (Exhibit 10.07 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
10.19**+	First Amendment effective Nov. 29, 2011 to the Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement) (Exhibit 10.17 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2011).
10.20**+	Second Amendment dated Oct. 26, 2011 to the Xcel Energy Senior Executive Severance and Change-in-Control Policy (Exhibit 10.18 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2011).
10.21**+	First Amendment dated Feb. 20, 2013 to the Xcel Energy Inc. Executive Annual Incentive Award Plan (as amended and restated effective Feb. 17, 2010) (Exhibit 10.01 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended March 31, 2013).
10.22**+	Fourth Amendment dated Feb. 20, 2013 to the Xcel Energy Senior Executive Severance and Change-in-Control Policy (Exhibit 10.02 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended March 31, 2013).
10.23**+	First Amendment dated May 21, 2013 to the Xcel Energy Inc. 2005 Long-Term Incentive Plan (as amended and restated effective Feb. 17, 2010) (Exhibit 10.21 to Form 10-Q of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2013).
10.24**+	Second Amendment dated May 21, 2013 to the Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement) (Exhibit 10.22 to Form 10-Q of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2013).
10.25**+	Xcel Energy Inc. 2005 Long-Term Incentive Plan Form of Long-Term Incentive Award Agreement (Exhibit 10.23 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2013).
10.26*	Amended and Restated Credit Agreement, dated as of Oct. 14, 2014 among Xcel Energy Inc., as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Exhibit 99.02 to Form 8-K of Xcel Energy, dated Oct. 14, 2014 (file no. 001-03034)).
12.01	Statement of Computation of Ratio of Earnings to Fixed Charges.
23.01	Consent of Independent Registered Public Accounting Firm.
31.01	Principal Executive Officer's certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.02	Principal Financial Officer's certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.01	Statement pursuant to Private Securities Litigation Reform Act of 1995.
101	The following materials from NSP-Minnesota's Annual Report on Form 10-K for the year ended Dec. 31, 2014 are formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income, (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Balance Sheets, (v) the Consolidated Statements of Stockholder's Equity, (vi) the Consolidated Statements of Capitalization, (vii) Notes to Consolidated Financial Statements, (viii) document and entity information, and (ix) Schedule II.

SCHEDULE II

NSP-MINNESOTA AND SUBSIDIARIES
VALUATION AND QUALIFYING ACCOUNTS
YEARS ENDED DEC. 31, 2014, 2013 AND 2012
(amounts in thousands)

		Additions			
	Balance at Jan. 1	Charged to Costs and Expenses	Charged to Other Accounts ^(a)	Deductions from Reserves ^(b)	Balance at Dec. 31
Allowance for bad debts:					
2014	\$ 20,216	\$ 17,193	\$ 5,469	\$ 19,941	\$ 22,937
2013	20,420	13,418	5,190	18,812	20,216
2012	23,004	11,241	5,874	19,699	20,420

^(a) Recovery of amounts previously written off.

^(b) Principally bad debts written off.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this annual report to be signed on its behalf by the undersigned thereunto duly authorized.

**NORTHERN STATES POWER COMPANY
(A MINNESOTA CORPORATION)**

Feb. 20, 2015

/s/ TERESA S. MADDEN

Teresa S. Madden

Executive Vice President, Chief Financial Officer and Director
(Principal Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities on the date indicated above.

/s/ BEN FOWKE

Ben Fowke

Chairman, Chief Executive Officer and Director
(Principal Executive Officer)

/s/ CHRISTOPHER B. CLARK

Christopher B. Clark

President and Director

/s/ TERESA S. MADDEN

Teresa S. Madden

Executive Vice President, Chief Financial Officer and
Director
(Principal Financial Officer)

/s/ JEFFREY S. SAVAGE

Jeffrey S. Savage

Senior Vice President, Controller

(Principal Accounting Officer)

/s/ MARVIN E. MCDANIEL, JR.

Marvin E. McDaniel, Jr.

Director

**SUPPLEMENTAL INFORMATION TO BE FURNISHED WITH REPORTS FILED PURSUANT TO SECTION 15(D) OF
THE ACT BY REGISTRANTS WHICH HAVE NOT REGISTERED SECURITIES PURSUANT TO SECTION 12 OF THE
ACT**

NSP-Minnesota has not sent, and does not expect to send, an annual report or proxy statement to its security holder.

Exhibit 12.01

NSP-MINNESOTA AND SUBSIDIARIES
STATEMENT OF COMPUTATION OF
RATIO OF EARNINGS TO FIXED CHARGES
(amounts in thousands, except ratio)

	Year Ended Dec. 31				
	2014	2013	2012	2011	2010
Earnings, as defined:					
Pretax income	\$ 603,005	\$ 575,203	\$ 515,665	\$ 544,630	\$ 455,416
Add: Fixed charges	233,386	227,301	243,317	249,587	243,620
Total earnings, as defined	<u>\$ 836,391</u>	<u>\$ 802,504</u>	<u>\$ 758,982</u>	<u>\$ 794,217</u>	<u>\$ 699,036</u>
Fixed charges, as defined:					
Interest charges	\$ 199,667	\$ 191,889	\$ 201,158	\$ 208,003	\$ 201,431
Interest component of leases	33,719	35,412	42,159	41,584	42,189
Total fixed charges, as defined	<u>\$ 233,386</u>	<u>\$ 227,301</u>	<u>\$ 243,317</u>	<u>\$ 249,587</u>	<u>\$ 243,620</u>
Ratio of earnings to fixed charges	<u>3.6</u>	<u>3.5</u>	<u>3.1</u>	<u>3.2</u>	<u>2.9</u>

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-192845 on Form S-3 of our report dated February 20, 2015, relating to the consolidated financial statements and financial statement schedule of Northern States Power Company, a Minnesota corporation, and subsidiaries appearing in this Annual Report on Form 10-K of Northern States Power Company, a Minnesota corporation, for the year ended December 31, 2014.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 20, 2015

CERTIFICATION

I, Ben Fowke, certify that:

1. I have reviewed this report on Form 10-K of Northern States Power Company (a Minnesota corporation);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: Feb. 20, 2015

/s/ BEN FOWKE

Ben Fowke

Chairman, Chief Executive Officer and Director

CERTIFICATION

I, Teresa S. Madden, certify that:

1. I have reviewed this report on Form 10-K of Northern States Power Company (a Minnesota corporation);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: Feb. 20, 2015

/s/ TERESA S. MADDEN

Teresa S. Madden

Executive Vice President, Chief Financial Officer and Director

OFFICER CERTIFICATION**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Northern States Power Company, a Minnesota corporation (NSP-Minnesota) on Form 10-K for the year ended Dec. 31, 2014, as filed with the SEC on the date hereof (Form 10-K), each of the undersigned officers of NSP-Minnesota certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to such officer's knowledge:

- (1) The Form 10-K fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) The information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of NSP-Minnesota as of the dates and for the periods expressed in the Form 10-K.

Date: Feb. 20, 2015

/s/ BEN FOWKE

Ben Fowke

Chairman, Chief Executive Officer and Director

/s/ TERESA S. MADDEN

Teresa S. Madden

Executive Vice President, Chief Financial Officer and Director

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document.

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to NSP-Minnesota and will be retained by NSP-Minnesota and furnished to the SEC or its staff upon request.

NSP-Minnesota Cautionary Factors

The Private Securities Litigation Reform Act provides a “safe harbor” for forward-looking statements to encourage disclosures without the threat of litigation, providing those statements are identified as forward-looking and are accompanied by meaningful, cautionary statements identifying important factors that could cause the actual results to differ materially from those projected in the statement. Forward-looking statements are made in written documents and oral presentations of NSP-Minnesota, Xcel Energy Inc. or any of its other subsidiaries. These statements are based on management’s beliefs as well as assumptions and information currently available to management. Such forward-looking statements are intended to be identified in this document by the words “anticipate,” “believe,” “estimate,” “expect,” “intend,” “may,” “objective,” “outlook,” “plan,” “project,” “possible,” “potential,” “should” and similar expressions. In addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements, factors that could cause NSP-Minnesota’s actual results to differ materially from those contemplated in any forward-looking statements include, among others, the following:

- Economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures;
- The risk of a significant slowdown in growth or decline in the U.S. economy, the risk of delay in growth recovery in the U.S. economy or the risk of increased cost for insurance premiums, security and other items as a consequence of past or future terrorist attacks;
- Trade, monetary, fiscal, taxation and environmental policies of governments, agencies and similar organizations in geographic areas where NSP-Minnesota has a financial interest;
- Customer business conditions, including demand for their products or services and supply of labor and materials used in creating their products and services;
- Financial or regulatory accounting principles or policies imposed by the FASB, the SEC, the FERC and similar entities with regulatory oversight;
- Availability or cost of capital such as changes in: interest rates; market perceptions of the utility industry, NSP-Minnesota, Xcel Energy Inc. or any of its other subsidiaries; or security ratings;
- Factors affecting utility and nonutility operations such as unusual weather conditions; catastrophic weather-related damage; unscheduled generation outages, maintenance or repairs; unanticipated changes to fossil fuel, nuclear fuel or natural gas supply costs or availability due to higher demand, shortages, transportation problems or other developments; nuclear or environmental incidents; cyber incidents; or electric transmission or natural gas pipeline constraints;
- Employee workforce factors, including loss or retirement of key executives, collective-bargaining agreements with union employees, or work stoppages;
- Increased competition in the utility industry or additional competition in the markets served by NSP-Minnesota, Xcel Energy Inc. and its other subsidiaries;
- State, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rate structures and affect the speed and degree to which competition enters the electric and natural gas markets; industry restructuring initiatives; transmission system operation and/or administration initiatives; recovery of investments made under traditional regulation; nature of competitors entering the industry; retail wheeling; a new pricing structure; and former customers entering the generation market;
- Environmental laws and regulations, including legislation and regulations relating to climate change, and the associated cost of compliance;
- Rate-setting policies or procedures of regulatory entities, including environmental externalities, which are values established by regulators assigning environmental costs to each method of electricity generation when evaluating generation resource options;
- Nuclear regulatory policies and procedures, including operating regulations and spent nuclear fuel storage;
- Social attitudes regarding the utility and power industries;
- Cost and other effects of legal and administrative proceedings, settlements, investigations and claims;
- Technological developments that result in competitive disadvantages and create the potential for impairment of existing assets;
- Risks associated with implementations of new technologies; and
- Other business or investment considerations that may be disclosed from time to time in SEC filings, including “Risk Factors” in Item 1A of this Form 10-K for the year ended Dec. 31, 2014, or in other publicly disseminated written documents.

NSP-Minnesota undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing review of factors should not be construed as exhaustive.

Minnesota
Nonregulated Business Activity Allocations
2016 Test Year Budget

Allocation	Allocation Method	Reasonableness of Allocation Method	Allocation Percent
Labor Related Overhead	Based on employee related expenses, office equipment, and supervision of the service provider.	This allocation represents the relationship between the costs to support labor with labor costs, and is applied to loaded labor.	14.6928%
Corporate Residual	Two-Factor Allocator based on number of employees and revenues relative to NSPM totals.	This allocation represents a fair comparison of the non-regulated business' relative size to the total company and is applied to the prior year actual pool of expenses incurred on behalf of the corporation	HomeSmart - 0.4187% Customer Owned Street Lighting - 0.0033%

**Cost Allocations Discovery - 2016 TY Electric Rate Case
Index**

Docket No.	IR No.		Question	Addressed in 2016 TY Case
12-961	DOC	143	Subject: Method Used to Allocate NSPM's Common A&G Costs Between Electric and Gas A. Please provide a definition of the term "supervised O&M" (Stitt, page 55, line 22).	Testimony p. 21
12-961	DOC	147	Subject: Work Order Testing A. Please provide a reconciliation of the work orders used in the 2014 test year as filed in Docket No. E002/GR-13-868 to the work orders used for the 2016 test year. Please explain why all changes were made.	Appendix A
12-961	DOC	1140	Subject: Allocations Based on Labor with Overtime Adjustment A. Please provide labor overtime hours and associated dollars for all Xcel operating companies for the years 2009 to 2014. B. Please provide budgeted labor overtime hours and associated dollars for all Xcel operating companies for the 2016 test year. Please include any study or other information to support the Company's statement that NSPM has more labor hours with overtime.	Appendix A
13-868	DOC	1103	Subject: Service Agreement with Xcel Energy Services Reference: Stitt Direct, page 44, lines 18-23 "We expect to make an Affiliated Interest filing by the end of December 2013, which would be in advance of the date on which Intervener Direct testimony will be due in this proceeding. In our filing, we will identify the effects of the changes on the 2014 Test Year, and notify all parties in this proceeding." Please provide a docket number for this Affiliated Interest filing. If this filing has not yet been made, please provide an updated estimate on when the Company plans to file.	Testimony p. 2

Docket No. E002/GR-15-826
Exhibit____(ARD-1), Appendix A

Docket No. E002/GR-12-961
Information Request No. DOC-147, Part A

Question:

Subject: Work Order Testing

- A. Please provide a reconciliation of the work orders used in the 2014 test year as filed in Docket No. E002/GR-13-868 to the work orders used for the 2016 test year. Please explain why all changes were made.

Response:

- A. Please see Attachment A to this response showing the net changes – three digit work order additions and deletions – between the 2014 and 2016 test years.

The 2014 test year included 119 three digit work orders, and the 2016 test year includes 126 three digit work orders. In the 2016 test year, the 126 work orders used to build the 2016 NSPM budget are shown in Exhibit____(ARD-1), Schedule 5, XES Allocation Statistics (as used in J.D. Edwards).

Additionally, included in Exhibit__(ARD-1) Schedule 5, XES Allocation Statistics (as used in J.D. Edwards) are 13 five digit workorders used to build the 2016 NSPM budget that were not used in the 2014 test year. The five digit workorders are used to charge out Information Technology costs to the appropriate companies.

Preparer: Adam Dietenberger
Title: Senior Manager
Department: Service Company Accounting

Docket No. E002/GR-12-961
Information Request No. DOC-147, Part A

Docket No. E002/GR-15-826
Exhibit___(ARD-1), Appendix A

Workorders Removed		
Workorder	Workorder Description	Why Workorder Was Removed
160	Corp. Strategy & Bus. Dev	This workorder has been closed, no dollars have been budgeted to this Work Order in the 2016 test year.
529	Mercury Interactive	This workorder is still being used by XES, however no dollars were budgeted to this work order in the 2016 test year.
Workorders Added		
Workorder	Workorder Description	Why Workorder Was Added
134	Audit Services - OpCos - Gas	There are budgeted dollars to this workorder for the 2016 test year, whereas no dollars were budgeted in the previous test year. The Audit Services OpCos Gas workorder includes the labor and non-labor costs for auditing operating companies gas utility, evaluating and improving risk management, ethical conduct and the implementation of best practices for operating companies gas utility, conducting financial operations and information system audits, performing audits and reviews for compliance with regulatory and legal requirements and contracts with vendors and other parties; establishing and reviewing internal controls for operating companies gas utility, establishing and reviewing SOX compliance requirements/control testing and evaluating contract risks for the operating companies gas utility.
162	Corp Strategy & Bus Dev - OpCo	There are budgeted dollars to this workorder for the 2016 test year, whereas no dollars were budgeted in the previous test year. The Corp Strategy & Bus Dev - OpCo services includes the labor and non-labor costs associated with studying developing and demonstrating new energy technologies for future utility uses; providing operating company strategy and planning support, and providing leadership for Xcel Energy's renewable energy strategy and business
163	Legal - OPCo Electric	There are budgeted dollars to this workorder for the 2016 test year, whereas no dollars were budgeted in the previous test year. The Legal OpCo Electric services includes the labor and non-labor costs for operating companies electric utility legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts
164	Legal - OPCo Gas	There are budgeted dollars to this workorder for the 2016 test year, whereas no dollars were budgeted in the previous test year. The Legal OPCo Gas NSPM, NSPW and PSCO Gas services includes the labor and non-labor costs for operating companies gas utility legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts
173	Legal - NSPM & NSPW Electric	There are budgeted dollars to this workorder for the 2016 test year, whereas no dollars were budgeted in the previous test year. The Legal NSPM & NSPW Electric includes the labor and non-labor costs for operating companies electric utility legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts
453	Transm Elec FERC 586	There are budgeted dollars to this workorder for the 2016 test year, whereas no dollars were budgeted in the previous test year. The Distribution Elec FERC 586 services include meter expenses labor and non-labor providing direction, operations, standards and processes relating to Xcel Energy operating companies i.e.: electric distribution meters standards and development, meter purchases, etc.
454	Transm Gas FERC 878	There are budgeted dollars to this workorder for the 2016 test year, whereas no dollars were budgeted in the previous test year. The Distribution Gas FERC 878 services include meter expenses labor and non-labor providing direction, operations, standards and processes relating to Xcel Energy Operating Companies i.e.: gas distribution meters standards and development, meter purchases, etc.
527	EMS-Distribution (Energy Mgmt System-SCADA)	There are budgeted dollars to this workorder for the 2016 test year, whereas no dollars were budgeted in the previous test year. The EMS provides supervisory control and data acquisition of substation devices through Remote Terminal Units (RTU's). EMS - Distribution system includes the labor and non-labor costs for application development and maintenance of the Electric Distribution Plant information operations.
563	SAP GL	The Workorder was created up to allocate labor and non-labor costs related to SAP GL expenses for the implementation of the new General Ledger system.

Docket No. E002/GR-15-826
Exhibit____(ARD-1), Appendix A

Docket No. E002/GR-12-961
Information Request No. DOC-1140, Parts A & B

Question:

Subject: Allocations Based on Labor with Overtime Adjustment

- A. Please provide labor overtime hours and associated dollars for all Xcel operating companies for the years 2009 to 2014.
- B. Please provide budgeted labor overtime hours and associated dollars for all Xcel operating companies for the 2016 test year. Please include any study or other information to support the Company's statement that NSPM has more labor hours with overtime.

Response:

- A. Please see Attachment A to this response for a schedule of direct labor overtime hours and associated dollars for all Xcel Energy operating companies for the years 2009-2014. Please note that the 2015 labor hours information is not available at this time.
- B. The chart below shows the direct labor overtime dollars included in the 2016 test year budget for all Xcel Energy operating companies. Please note: Xcel Energy can only provide budgeted overtime dollars, because we do not budget overtime hours in our system.

Direct Labor Overtime Dollars in the 2016 Budget		
Company	2016	Percentage
NSPM	\$ 40,693,224.91	54.66%
NSPW	\$ 3,995,660.55	5.37%
PSCo	\$ 21,840,392.65	29.33%
SPS	\$ 7,924,108.92	10.64%
Total	\$ 74,453,387.03	100.00%

Preparer: Adam Diitenberger
Title: Senior Manager
Department: Service Company Accounting

Docket No. E002/GR-12-961
Information Request No. DOC-1140, Attachment A

Docket No. E002/GR-15-826
Exhibit___(ARD-1), Appendix A

Direct Labor Overtime Hours and Associated Dollars

Company	2009 \$	%	2009 Hours	%	2010 \$	%	2010 Hours	%	2011 \$	%	2011 Hours	%	2012 \$	%	2012 Hours	%
NSPMN	\$56,860,909	61.03%	1,063,950	60.38%	\$ 60,683,947	58.08%	1,079,897	57.19%	\$ 79,550,274	61.38%	1,410,097	61.34%	\$ 68,685,401	57.14%	1,159,854	56.37%
NSPWI	\$ 4,278,656	4.59%	80,237	4.55%	\$ 6,983,685	6.68%	124,711	6.60%	\$ 7,651,155	5.90%	132,598	5.77%	\$ 8,246,722	6.86%	139,905	6.80%
PSCO	\$21,911,816	23.52%	405,038	22.98%	\$ 26,368,229	25.24%	468,440	24.81%	\$ 29,179,395	22.52%	495,460	21.55%	\$ 28,167,968	23.43%	465,684	22.63%
SPS	\$10,122,265	10.86%	213,001	12.09%	\$ 10,446,971	10.00%	215,315	11.40%	\$ 13,218,391	10.20%	260,616	11.34%	\$ 15,115,041	12.57%	292,215	14.20%
Totals	\$93,173,646	100.00%	1,762,226	100.00%	\$ 104,482,832	100.00%	1,888,363	100.00%	\$ 129,599,216	100.00%	2,298,770	100.00%	\$ 120,215,133	100.00%	2,057,657	100.00%