

Rebuttal Testimony  
Scott B. Brockett

Before the North Dakota Public Service Commission  
State of North Dakota

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

Case No. PU-12-813  
Exhibit\_\_\_ (SBB-1)

**Jurisdictional Demand Allocator**

August 12, 2013

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1 **I. INTRODUCTION AND QUALIFICATIONS**

2  
3 Q. PLEASE STATE YOUR NAME AND TITLE.

4 A. My name is Scott B. Brockett. I am Director of Regulatory Administration and  
5 Compliance for Xcel Energy Services Inc.  
6

7 Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

8 A. I have a B.A. in English and Economics and an M.A. in Economics. For the  
9 first 16 years of my professional career, I worked for the Minnesota Department  
10 of Public Service, a state agency charged with representing the broad public  
11 interest in utility proceedings before the Minnesota Public Utilities Commission.  
12 I then worked for over five years for Consumers Energy – a gas and electric  
13 utility based in Jackson, Michigan – as a Pricing Supervisor. Since July 2004, I  
14 have been employed by Xcel Energy Services, Inc., the registered public utility  
15 company holding company parent of Northern States Power Company -  
16 Minnesota. In my current position, I am responsible for or contribute to a  
17 variety of different filings before the Colorado Public Utilities Commission. I  
18 also provide technical support on pricing, tariff and financial issues. My resume  
19 is provided as Exhibit \_\_\_\_ (SBB-1), Schedule 1.  
20

21 Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

22 A. No.  
23

24 Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

25 A. I will respond to the Direct Testimony of North Dakota Public Service  
26 Commission Advocacy Staff Witness Dr. Karl R. Pavlovic. More specifically, I  
27 will respond to Dr. Pavlovic's recommendation regarding the allocation of  
28 production and transmission costs to the North Dakota retail jurisdiction. I will

1 explain why the Company believes the 12 CP Method results in a more equitable  
2 and stable allocation of costs among jurisdictions than the 1 CP Method that Dr.  
3 Pavlovic proposes.  
4

5 Q. PLEASE SUMMARIZE YOUR RESPONSE TO DR. PAVLOVIC'S TESTIMONY.

6 A. The Company's proposed allocation method is referred to as "The Sum of the 12  
7 Monthly Coincident Peak Method" (12 CP Method). It is based on the North  
8 Dakota retail jurisdiction's contributions to each of the 12 monthly coincident  
9 peak demands on the NSPM system during the 2013 test year. Dr. Pavlovic  
10 proposes to allocate production and transmission costs using an allocation  
11 method referred to as the "Single Coincident Peak Method" (1 CP Method).  
12

13 In previous rate dockets, the Commission established the following three-part  
14 test for evaluating the appropriateness of an allocator:

- 15 • Does it reasonably reflect the incremental cost caused by each  
16 jurisdiction?
- 17 • Is it consistently applied among each of the Company's jurisdictions?
- 18 • Is it understandable, inexpensive to administer, and does not result in  
19 large swings in jurisdictional cost responsibility over time?<sup>1</sup>  
20

21 Using this three-part test, I will demonstrate that the Company's 12 CP Method:

- 22 • Better reflects cost causality than the 1 CP method;
- 23 • Provides a straightforward and a more stable allocator than the 1 CP  
24 Method; and

---

<sup>1</sup> *Northern States Power Company, Electric Rates*, PU-400-87-6, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER dated June 23, 1987 at 6; see also, *Northern States Power Company, Electric Rates*, PU-400-92-399 FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER dated December 15, 1992 at 6; and ORDER ON RECONSIDERATION Dated April 7, 1993 at 2.

- 1           • Is the preferred allocation method among the various jurisdictions  
2           served by the Company.

3  
4 Q. PLEASE SUMMARIZE WHY THE 12 CP METHOD BETTER REFLECTS COST  
5 CAUSATION PRINCIPLES.

6 A. The Company determines its total effective capacity and mix of production  
7 facilities primarily to meet the following two major objectives:

- 8           • Reliably serve customers during those hours when their loads are  
9           highest; and  
10          • Minimize total system energy costs throughout the year.

11  
12 The 1 CP Method advocated by Dr. Pavlovic is based on the assumption that  
13 100 percent of our fixed production costs are incurred to meet the first goal –  
14 meeting our peak demand. Conversely, the Company's 12 CP Method  
15 recognizes that the level of our total fixed production costs is a function of our  
16 need to meet and balance *both* goals.

17  
18 In other words, there is more than one combination of resource types that could  
19 be employed to meet a given system's peak demand. The optimal combination,  
20 in terms of meeting the energy needs of all customers at the lowest cost, depends  
21 on the system's load profile during the rest of the year. The 12 CP Method  
22 better reflects each jurisdiction's responsibility for the pure capacity or reliability  
23 component of our fixed generation costs.

24  
25 Similarly, our transmission system is designed to economically meet both system  
26 and local demands. The 1 CP Method focuses *only* on total system needs, while

1 the 12 CP Method recognizes our need to serve the monthly peak demands in  
2 each jurisdiction.

3  
4 Q. PLEASE SUMMARIZE WHY THE 12 CP METHOD IS THE MOST CONSISTENTLY  
5 APPLIED ALLOCATION METHOD.

6 A. The 12 CP Method is used in all three of the Company's retail jurisdictions, and  
7 is also used by the Midwest Independent System Operator (MISO). Using a  
8 consistent allocator provides the Company the opportunity to recover 100  
9 percent of its prudently incurred costs – no more, and no less. The Commission  
10 has, in part, approved using the 12 CP Method out of an acknowledgement that  
11 it achieves uniform treatment among the Company's jurisdictions. At the same  
12 time, in proceedings where interveners have proposed the 1 CP Method for the  
13 Company, the Commission has consistently rejected these proposals.  
14

15 Q. PLEASE SUMMARIZE WHY THE 12 CP METHOD PRODUCES THE MOST STABLE  
16 ALLOCATOR.

17 A. The stability afforded by the 12 CP Method stems from its use of multiple loads  
18 (multiple data points). Conversely, Dr. Pavlovic's 1 CP Method uses only one  
19 monthly demand data point, which makes it susceptible to significant swings in  
20 results from year to year. Dr. Pavlovic proposes to use a three-year average of  
21 historical 1 CP peak loads to ensure consistency with other financial adjustments  
22 that the Staff proposes in this proceeding. One ancillary consequence of this  
23 averaging is that it partially addresses the inherent volatility of the 1 CP Method.  
24 Unfortunately, this same refinement introduces inaccuracies that I will address  
25 later.  
26  
27

1 Q. WHICH ALLOCATION METHOD PRODUCES MORE STABLE RESULTS?

2 A. As shown in Exhibit \_\_\_(SBB-1), Schedule 2, the annual variations in the  
3 jurisdictional allocator (and the resulting allocation of costs) derived from the 12  
4 CP Method are much less than those of the 1 CP Method. After applying the  
5 appropriate transmission loss factors, the range of 1 CP allocator values (1.65  
6 percentage points) from 2007 through the 2013 test year is more than *3.5 times*  
7 that of the range of 12 CP allocator values (0.44 percentage points). As I stated  
8 above, the use of one monthly demand data point renders the 1 CP Method  
9 susceptible to significant swings in results from year to year.

10

11 For all of these reasons, Dr. Pavlovic's proposed allocator adjustments should be  
12 rejected.

13

## 14 II. COST CAUSALITY – PRODUCTION FUNCTION

15

16 Q. PLEASE EXPLAIN THE CONTEXT IN WHICH COSTS ARE ALLOCATED AMONG  
17 JURISDICTIONS IN RETAIL RATE CASES.

18 A. Although the specific issue I address in my Rebuttal Testimony is the allocation  
19 of fixed production and transmission costs, it is important to remember the  
20 context in which such allocations occur. The allocation of costs is actually the  
21 last step of the following three-step process:

22

23

24

25

26

27

- 1) Divide costs into their various functions (production, transmission, distribution, etc.).
- 2) Classify these costs according to why they are incurred (as a function of meeting system peak demands, meeting localized peak demands, meeting energy needs, etc.).
- 3) Allocate these costs among jurisdictions and customer classes.

1 While these steps are occasionally combined or not separately identified in  
2 costing analyses, it is helpful to remember this sequence as a general rule.  
3

4 Q. IS THERE ANY ONE UNIVERSALLY-ACCEPTED WAY TO CLASSIFY AND ALLOCATE  
5 FIXED COSTS THAT ARE FUNCTIONALIZED AS PRODUCTION COSTS?

6 A. No. The authors of the *Electric Utility Cost Allocation Manual* (NARUC Manual),  
7 prepared by the National Association of Regulatory Utility Commissioners,  
8 discuss many ways to classify and allocate production costs. The NARUC  
9 Manual is a commonly cited primer on the classification and allocation of electric  
10 utility costs. In fact, Dr. Pavlovic refers to the NARUC Manual in his Direct  
11 Testimony.  
12

13 Q. PLEASE ELABORATE ON THE NARUC DISCUSSION.

14 A. Among the different allocations methods discussed in the NARUC Manual are  
15 the 12 CP Method and the 1 CP Method. The authors explain trends in cost  
16 classification and allocation, and the basis for and application of the various  
17 methods. They also identify the conditions under which the case for using a  
18 particular allocation method may be stronger or weaker. Nonetheless, they do  
19 not advocate the universal use of one single method. The last sentence in the  
20 section on production costs reinforces this point:

21 These methods are laid out here to reveal their flexibility; they can  
22 be seen as maps and the road you take is the one that best suits  
23 you.  
24

25 Each regulatory commission must decide which of the various allocation  
26 methods is most appropriate for the utilities within its jurisdiction. Moreover, a  
27 commission may order different methods for different utilities, depending on  
28 each utility's particular circumstances.

1 Q. GIVEN THIS BACKGROUND, PLEASE EXPLAIN WHY THE 12 CP METHOD BETTER  
2 REFLECTS THE INCREMENTAL COSTS CAUSED BY THE VARIOUS COMPANY  
3 JURISDICTIONS.

4 A. I reach the conclusion that the 12 CP Method better reflects cost causality for  
5 two reasons:

6 1) The 12 CP Method better recognizes that the total fixed costs of the  
7 Company's generating units are based on *both* of the Company's two  
8 primary goals of: (1) *reliably meeting customers' peak energy needs*; and (2)  
9 *minimizing the total costs of meeting customers' energy needs throughout the year*.

10 2) Even to the extent the fixed production costs are considered to be  
11 incurred for reliability reasons, the 12 CP Method better captures the  
12 drivers of these reliability costs.

13  
14 Q. PLEASE EXPLAIN FURTHER THE FIRST REASON FOR REACHING THIS CONCLUSION.

15 A. The costs of meeting the reliability goal are often referred to as "demand-related"  
16 costs, meaning that they are incurred to ensure that sufficient generation capacity  
17 is available to reliably serve customers during system peak periods. The capital  
18 and fixed O&M costs of generating units are often cited as examples of demand-  
19 related costs. The costs of meeting customers' energy needs over all hours of a  
20 year are often referred to as "energy-related" costs. Examples of energy-related  
21 costs are fuel and variable operations and maintenance (O&M) expenses.

22  
23 As I describe below, by considering loads during all 12 months, the 12 CP  
24 Method recognizes that *loads in all months* contribute to the levels of the  
25 Company's fixed production costs. In contrast, the 1 CP Method assumes that  
26 loads during the *single system peak hour* of the 8,760 hours in a year entirely drive  
27 the level of a utility's fixed production costs. By extension, the 1 CP Method

1 assumes that loads in the other 8,759 hours have no bearing on the mix of  
2 resources and level of fixed production costs. This assumption ignores the dual  
3 goals that the Company balances when deciding on the total effective capacity  
4 and mix of its production plant portfolio.  
5

6 Q. PLEASE FURTHER DISCUSS HOW THE 12 CP METHOD RECOGNIZES THIS SPLIT  
7 BETWEEN DEMAND- AND ENERGY-RELATED COSTS.

8 A. Many utilities, including the Company, have historically recognized that the fixed  
9 costs of production plants, other than peaking facilities, are far above the levels  
10 required simply to ensure reliable service during system peak hours. Stated  
11 simply, the fixed costs of intermediate and baseload units above the fixed costs  
12 of installing the least-cost capacity resource option (a peaking plant) of  
13 equivalent effective capacity can be fairly considered energy-related costs.  
14

15 Consider the investment and operating costs of a baseload plant compared to a  
16 peaking facility. The much higher investment costs of a baseload plant are  
17 justified because of the ability of such plants to provide lower-cost energy  
18 throughout the year. In contrast, the lower capital costs of peaking units are  
19 offset by the much higher fuel costs, limiting the usefulness of such facilities to  
20 providing service during peak periods. The additional capital costs for  
21 intermediate and baseload plants are incurred to lower system energy costs over  
22 an entire year or multiple years. More specifically, system loads during different  
23 periods most directly affect specific levels of production investment in the  
24 following manner:

- 25 • System loads during the *off-peak* periods most directly affect the level of  
26 required *baseload* investment.
- 27 • System loads during the *shoulder* periods (in excess of off-peak loads)

1 most directly affect the level of *intermediate* investment.

- 2 • System loads during *peak* periods (in excess of loads during shoulder  
3 periods) most directly affect the level of investment in *peaking plants*.

4  
5 Again, as I stated previously, the Company's 12 CP Method recognizes the dual  
6 drivers of fixed production costs, while the 1 CP Method does not capture the  
7 impact of the energy-related drivers of fixed production costs.

8  
9 Q. PLEASE EXPLAIN FURTHER THE SECOND REASON FOR CONCLUDING THE 12 CP  
10 METHOD BETTER REFLECTS COST CAUSATION.

11 A. We plan our system to meet customers' energy needs with a very high degree of  
12 reliability. Obviously, loads during peak hours are a driver of the Company's  
13 total capacity needs, which our 12 CP Method recognizes through its use of  
14 multiple peak loads. While Dr. Pavlovic correctly observes that NSPM is a  
15 summer-peaking utility, his 1 CP Method assumes loads during a single hour  
16 drive the Company's capacity-related production costs. I have two fundamental  
17 concerns with this approach.

18  
19 First, the system peak hour can occur in a number of different hours of the day  
20 in any summer month. As illustrated in the load data Dr. Pavlovic includes in his  
21 Exhibit \_\_\_ (KRP-2), the coincident hourly peak load on the Company's system  
22 from 2007 through 2012 has occurred in June, July and August. Moreover, the  
23 coincident hourly peak load in September 2007 was *very close* to being the annual  
24 coincident peak load during that year. This historical experience illustrates that  
25 the month in which the annual peak demand occurs can vary (and has varied)  
26 from year to year. Allocating a majority of costs to jurisdictions based on either  
27 projected or actual loads during one hour (using one data point) runs the risk of

1 unduly emphasizing either systemic or one-time anomalies in the various  
2 jurisdictional loads during that one hour.

3  
4 Q. PLEASE EXPLAIN WHY NON-REPRESENTATIVE ALLOCATORS CAN RESULT FROM  
5 USING A SINGLE DATA POINT AS THE BASIS FOR THESE COSTS.

6 A. Non-representative allocators can result for a number of reasons. For example,  
7 during the system peak hour in a given year, a particular large business may be  
8 operating at levels significantly lower than normal due to market conditions,  
9 maintenance, or other reasons. Similarly, if a historical hourly peak load is used,  
10 unusually hot weather may lead to a disproportionately high allocation of  
11 production costs to jurisdictions with relatively high space-cooling loads. During  
12 cool summers the opposite distortion may occur.

13  
14 Dr. Pavlovic uses the average of the 1 CP in three historical years, which may  
15 mitigate the variability problem to some degree. However, if that historical  
16 average is not representative of future coincident peak loads, then the use of  
17 such an average will still produce biased results in terms of reflecting the  
18 incremental production costs each jurisdiction imposes. The use of loads in  
19 multiple hours, a requirement of the 12 CP Method, coupled with the use of  
20 forecasted weather normalized 2013 coincident peak demands, reduces the risk  
21 of non-representative allocators.

22  
23 Q. WHAT IS YOUR SECOND CONCERN ABOUT THE ASSUMPTION THAT LOADS DURING  
24 A SINGLE HOUR DRIVE THE COMPANY'S CAPACITY-RELATED PRODUCTION COSTS?

25 A. While the Company certainly plans on ensuring sufficient capacity to meet  
26 summer peak loads, the drivers of generation capacity needs are not limited to  
27 these projected peaks. We plan our production system to meet our forecasted

1 peak loads, including a targeted reserve margin to account for contingencies such  
2 as higher-than-anticipated peak demand or forced (unplanned) outages. While  
3 variations in peak loads or forced outages around their expected values may be  
4 difficult to predict, a utility has considerable flexibility in the timing of scheduled  
5 maintenance.

6  
7 For example, a summer-peaking utility may concentrate its routine maintenance  
8 in non-summer months. A utility with pronounced summer and winter peaks  
9 may schedule as much maintenance as possible during the shoulder months in  
10 the spring and fall. In either case, the probability of not being able to serve load  
11 may not vary as much as expected between months, once planned maintenance  
12 is considered. In other words, the probability of “unserved” load due to  
13 inadequate generation resources is a function not only of forecasted peak loads  
14 and forced outages, but also of the timing of scheduled maintenance.

15  
16 This probability of unserved load – based on the factors discussed above – is a  
17 key barometer of whether a utility has sufficient generation capacity to serve  
18 customers reliably during the year. By extension, one reasonable way to allocate  
19 capacity-related generation costs to different periods is to use the respective  
20 probabilities of unreliable service (unserved load) during these same periods.

21  
22 The salient advantage of using these probabilities is that period-specific reliability  
23 risks can be specifically identified, given projected loads, the probability of forced  
24 outages, and planned maintenance. By extension, the differences in these  
25 probabilities among periods can provide guidance on what loads truly drive a  
26 need for additional capacity. As I will explain below, the results of such an  
27 analysis for NSPM confirms the inappropriateness of assuming the reliability

1 risks attributable to inadequate generation resources are concentrated in one  
2 hour. This analysis suggests that many different months contribute significantly  
3 to the annual probability of unserved load.  
4

5 Q. DOES THE COMPANY'S PROPOSED 12 CP METHOD AFFORD A GREATER WEIGHT  
6 TO MONTHS WITH HIGHER PEAK LOADS?

7 A. Yes. The Company's derivation of the 12 CP allocator is based on the sum of  
8 the 12 monthly coincident peak loads for the North Dakota jurisdiction divided  
9 by the sum of the 12 monthly coincident peak loads for NSPM. In this respect,  
10 months with relatively high peak loads (such as July) contribute more to the 12  
11 CP allocator than months with relatively small peak loads (such as October). In  
12 this sense, the Company's 12 CP Method could be characterized as a weighted  
13 method.  
14

15 Q. IS THIS APPROACH TO DEVELOPING THE 12 CP ALLOCATOR ALSO APPLIED IN  
16 OTHER NSPM JURISDICTIONS?

17 A. Yes, we use the 12 CP allocator in all NSPM jurisdictions and the same approach  
18 to developing the 12 CP allocator in each jurisdiction.  
19

20 Q. DO YOU HAVE ANY EVIDENCE OF THE TRUE PROBABILITIES OF UNSERVED LOAD  
21 AFTER SCHEDULED MAINTENANCE IS CONSIDERED?

22 A. Yes. In March 2013 the Company completed a Loss of Load Probability Study  
23 to estimate the probability of unserved load due to a lack of generation resources  
24 during different periods in calendar year 2014. This study incorporates planned  
25 maintenance into the estimated availability of generation resources during various  
26 periods. This study concludes that the average hourly loss of load probabilities  
27 in the winter months of December through March are lower than, but reasonably

1 comparable to, the loss of load probabilities during the four summer months. In  
2 other words, the probabilities of load loss during the summer and winter seasons  
3 do not vary as much as one might conclude from reviewing monthly coincident  
4 peak loads only. Moreover, as explained more fully below, an allocator based on  
5 this study more closely reflects the results of the 12 CP Method than the 1 CP  
6 Method.

7  
8 Q. PLEASE DESCRIBE HOW YOU USED THIS LOSS OF LOAD PROBABILITY STUDY TO  
9 DERIVE A JURISDICTIONAL ALLOCATOR FOR PRODUCTION PLANT, AND COMPARE  
10 THIS APPROACH WITH THE 1 CP METHOD AND 12 CP METHOD.

11 A. For purposes of this discussion, I will refer to the method of deriving an  
12 allocator based on loss of load probabilities as the "Relative LOLP Method."  
13 This method is similar to the 1 CP Method and the 12 CP Method in that the  
14 derived allocator is based on the contributions of a given jurisdiction to one or  
15 more system coincident peak loads. The basic difference between the three  
16 methods is how peak loads in various months are weighted to derive a demand  
17 allocator.

18  
19 The 1 CP Method implicitly assigns a weight of 100 percent to the highest  
20 monthly peak load during the year, and a weight of 0 percent to the other 11  
21 monthly peak loads. The 12 CP Method (as applied in this proceeding) assigns  
22 weights to the 12 monthly peak loads based solely on the differences in their  
23 magnitudes. The Relative LOLP Method assigns a weight to a monthly peak  
24 load equal to the probability of unserved load during that month as a percentage  
25 of the annual probability of unserved load. These monthly probabilities of  
26 unserved load capture not only projected loads during the month, but also  
27 projected forced outage rates and maintenance schedules.

1 I have derived the allocations to the North Dakota jurisdiction, both before and  
2 after the application of the transmission loss adjustment, on pages 1 through 4 of  
3 Exhibit \_\_\_\_ (SBB-1), Schedule 2. This comparison is provided for each of the  
4 historical years from 2007 through 2012, as well as the 2013 forecasted test year.  
5 I rely on the same data that Dr. Pavlovic uses in his Exhibit \_\_\_\_ (KRP-2). The  
6 results are summarized on page 5 of Schedule 2.  
7

8 Q. WHAT DO YOU CONCLUDE FROM THIS ANALYSIS?

9 A. The results from applying the 12 CP Method are very similar to the results from  
10 applying the Relative LOLP Method, which demonstrates that demand-related  
11 production costs (costs incurred to ensure reliable service) are a function of peak  
12 loads in *multiple* months, not just the one month during which the annual  
13 coincident peak hourly demand happens to occur on a historical or forecasted  
14 basis.  
15

16 In contrast, the results of the 1 CP Method differ significantly from the results of  
17 the other two methods, which raises concerns about its ability to appropriately  
18 capture the drivers of capacity-related or reliability costs.  
19

20 Q. DOES THIS MEAN YOU ARE ADVOCATING THE USE OF THE RELATIVE LOLP  
21 METHOD IN LIEU OF THE 12 CP METHOD?

22 A. No. I believe the 12 CP Method is better-suited to capturing the energy-related  
23 component of fixed generation costs. Even to the extent the fixed production  
24 costs are classified as capacity-related costs, the allocation of such costs based on  
25 monthly loss of load probabilities is not without difficulties. For example, the  
26 Relative LOLP Method does not address whether higher peak loads in non-  
27 summer months would be accommodated through additional generation

1 resources, modified maintenance schedules, other initiatives, or some  
2 combination of these potential responses.

3  
4 Nonetheless, the resulting jurisdictional allocations using the Relative LOLP  
5 Method do serve as a useful check on the reasonableness of the 12 CP and 1 CP  
6 Methods, to the extent the fixed production costs are considered to be demand-  
7 related. This comparison suggests that the 12 CP Method is more reasonable  
8 than the 1 CP Method.

9  
10 Q. WHAT DO YOU CONCLUDE FROM YOUR ASSESSMENT OF THESE METHODS IN  
11 TERMS OF REFLECTING THE INCREMENTAL PRODUCTION COSTS CAUSED BY THE  
12 THREE COMPANY JURISDICTIONS?

13 A. I conclude that the 12 CP Method better satisfies this Commission criterion than  
14 the 1 CP Method.

15  
16 **III. COST CAUSALITY – TRANSMISSION FUNCTION**

17  
18 Q. DO THE SAME CONSIDERATIONS YOU OUTLINED FOR EVALUATING THE  
19 APPROPRIATE ALLOCATION OF FIXED PRODUCTION COSTS ALSO APPLY TO THE  
20 ALLOCATION OF TRANSMISSION COSTS?

21 A. Yes, in part. My same comments apply regarding the three-step costing process  
22 and the need to exercise judgment. But while the transmission system entails  
23 some substitution of capital and fuel costs in terms of considering energy losses  
24 in system design, the capital and fuel trade-offs are not as pronounced as they are  
25 with production plant.

26  
27 In other words, the energy savings from reducing transmission losses do not rise

1 to the significance of the energy savings that justify the additional capital costs of  
2 production plant. That is why – to the best of my knowledge – there has been  
3 little interest in explicitly stratifying (classifying) transmission plant into capacity-  
4 and energy-related components. However, the use of transmission plant for  
5 energy transfers is an important cost driver.  
6

7 Q. WHAT METHODS FOR ALLOCATING TRANSMISSION COSTS ARE DISCUSSED IN THE  
8 NARUC MANUAL?

9 A. Six methods are discussed, which include the 12 CP Method and the 1 CP  
10 Method.  
11

12 Q. WHAT FACTS SPECIFIC TO THE COMPANY'S TRANSMISSION SYSTEM SHOULD THE  
13 COMMISSION CONSIDER?

14 A. Two facts are pertinent. First, the Company's transmission system is not  
15 designed based on its system peak. The Company designs the various segments  
16 of its transmission system to meet the peak demands of the specific regions  
17 served by each segment of the system. These localized peak demands may also  
18 include the impacts of transmitting energy for third-parties. Moreover, these  
19 regional peak demands are not necessarily coincident with the NSPM coincident  
20 peak, and may occur in the winter. For example, the Company is currently  
21 investing over \$50 million in the transmission system in the Minot area. This  
22 investment is planned to meet the peak load in the Minot region, not the overall  
23 NSPM peak load.  
24

25 Second, MISO determines how the transmission system will be used in its  
26 footprint – including the NSPM transmission system. The MISO tariff uses the  
27 12 CP Method as a basis for its monthly billings.

1 Q. IN YOUR JUDGEMENT, WHAT ALLOCATION METHOD BEST MEETS THE  
2 COMMISSION'S FIRST CRITERION – THE ACCURATE REFLECTION OF COST  
3 CAUSALITY?

4 A. Based on the above discussion, I believe that the 12 CP Method better reflects  
5 the cost drivers of the NSPM transmission system than the 1 CP Method.  
6

#### 7 IV. CONSISTENT APPLICATION AMONG UTILITIES

8  
9 Q. IS THE CONSISTENT APPLICATION OF ALLOCATORS AMONG JURISDICTIONS AN  
10 IMPORTANT CONSIDERATION TO THE COMMISSION?

11 A. Yes. As I mentioned previously, one of the Commission's three criteria for  
12 evaluating an allocator has been whether it is used consistently across the utility's  
13 jurisdictions.  
14

15 Q. IS THIS CRITERION IMPORTANT TO THE COMPANY AS WELL?

16 A. Yes. Unless a consistent allocator is used across all jurisdictions, there is a risk  
17 that the Company will under- or over-collect our total costs. In either case, the  
18 outcome is not optimal. In contrast, the use of a consistent allocator avoids  
19 over- or under-collections.  
20

21 Q. DIFFERENT COMMISSIONS OFTEN REACH DIFFERENT CONCLUSIONS REGARDING  
22 THE VARIOUS COMPONENTS OF A UTILITY'S TEST-YEAR COSTS. WHY SHOULD  
23 REGULATORS BE CONCERNED ABOUT APPROVING DIFFERENT JURISDICTIONAL  
24 ALLOCATORS?

25 A. The consequences of two Commissions approving two different jurisdictional  
26 allocators are not consistent with the goal of equitable regulation, and can be  
27 distinguished from the consequences of different decisions regarding other test-

1 year costs. Under traditional regulation, two different Commissions assessing the  
2 prudence of a given cost often reach different conclusions. For example, one  
3 Commission may decide that the utility's test-year labor costs are at appropriate  
4 levels, while another Commission may order a partial disallowance on specific  
5 grounds. Similarly, two Commissions might reach different decisions regarding  
6 the prudence of the utility's capital expenditures or its required return on equity.  
7 These different decisions and resulting financial implications to the utility are  
8 common and are consistent with the traditional goals of economic regulation,  
9 assuming both Commissions base their decisions on record evidence.

10  
11 Conversely, the result of different decisions regarding jurisdictional cost  
12 allocations is an under- or over-recover of the utility's prudently incurred costs to  
13 provide service. For discussion purposes, let's suppose the end result of  
14 approving two different jurisdictional allocators is that the utility's rates will  
15 under-recover its expected costs of service. This scenario amounts to a de facto  
16 disallowance. However, this disallowance is not based on any findings of  
17 imprudence regarding the utility's planning, its day-to-day operations of its  
18 system, or the costs it incurs for such planning and operations. Instead, the  
19 disallowance stems from different views of how a prudently incurred pie of costs  
20 should be sliced and allocated among states and, ultimately, various customer  
21 groups. The slice of pie not collected through rates is still a prudently incurred  
22 cost, even if it is left on the table.

23  
24 For this reason, I believe the Commission was wise to include the consistency of  
25 allocators across jurisdictions as one of its three evaluation criteria.

1 Q. WHICH ALLOCATOR IS MORE COMMONLY USED ACROSS THE COMPANY'S  
2 JURISDICTIONS?

3 A. The 12 CP Method is used in all of the NSPM jurisdictions. The Commission  
4 has historically approved the 12 CP Method to allocate fixed production and  
5 transmission costs to the North Dakota retail jurisdiction. Moreover, the 12 CP  
6 Method has also been approved by the Regulatory Commissions in both  
7 Minnesota and South Dakota to allocate fixed production and transmission costs  
8 to their respective retail jurisdictions.<sup>2</sup> FERC also uses the 12 CP Method for  
9 wholesale service, and, as I noted previously, MISO also uses the 12 CP Method  
10 as a basis for its monthly transmission billings. The 1 CP Method is not  
11 currently approved for any of the three retail jurisdictions or the wholesale  
12 jurisdiction served by the Company.

13  
14 Q. IS THERE ANY EVIDENCE THAT THE 12 CP METHOD IS MORE COMMONLY-USED  
15 ACROSS THE COUNTRY TO ALLOCATE FIXED PRODUCTION COSTS?

16 A. Yes. The authors of the NARUC Manual state the following:

17 Over time it became apparent to some that hours other than the  
18 peak hour were critical from the system planner's perspective, and  
19 utilities moved toward multiple peak allocation methods. The  
20 Federal Energy Regulatory Commission began encouraging the  
21 use of a method based on the 12 monthly peak demands, and  
22 many utilities accordingly adopted this approach for allocating  
23 costs within their retail jurisdictions as well as their resale markets.  
24

25 The NARUC Manual was published in January 1992. I have not conducted any  
26 study to determine whether this cited trend has been reversed in recent years.  
27 Nonetheless, I am unaware of such a reversal, and know of no movement

---

<sup>2</sup> In South Dakota, the SDPUC recently approved a revenue requirement using the 12 CP Method for allocation of production and transmission costs (April 18, 2013 Order in Docket No. EL12-046). In Minnesota, the 12 CP Method was also used in the jurisdictional cost of service study in Docket E002/GR-12-961.

1 nationally towards the 1 CP Method.

2  
3 Q. WHAT DO YOU CONCLUDE FROM YOUR ASSESSMENT OF WHICH ALLOCATION  
4 METHOD BEST MEETS THE COMMISSION'S CRITERION OF BEING CONSISTENTLY  
5 APPLIED ACROSS JURISDICTIONS?

6 A. I conclude that the 12 CP Method is currently used to jurisdictionally allocate  
7 production and transmission in all of the NSPM jurisdictions. MISO and FERC  
8 also use the 12 CP Method. Moreover, I am unaware of any broad trend toward  
9 the use of the 1 CP Method. Consequently, I believe the 12 CP Method best  
10 satisfies this Commission criterion.

11  
12 **V. TRANSPARENCY, COST OF ADMINISTERING,**  
13 **AND STABILITY OF RESULTS**  
14

15 Q. WHICH OF THE TWO ALLOCATION METHODS BEST MEETS THE COMMISSION  
16 CRITERION OF BEING EASY TO UNDERSTAND, INEXPENSIVE TO ADMINISTER, AND  
17 STABLE OVER TIME?

18 A. Both methods are easy to understand and inexpensive to administer. However, I  
19 believe the 12 CP Method is superior to the 1 CP Method in terms of providing  
20 a stable allocator and mitigating volatility in the allocation of costs over time.

21  
22 Q. WHY DO YOU CONCLUDE THAT THE 12 CP METHOD RESULTS IN MORE STABLE  
23 RESULTS OVER TIME?

24 A. The 1 CP Method relies on *one hourly load* during the year, while the 12 CP  
25 Method uses 12 monthly loads – one for each month of the year. As I explained  
26 previously, the use of one annual data point entails a greater risk of instability  
27 than the use of 12 data points. On a long-term basis, I would expect the 12 CP

1 Method to result in more consistent allocations of fixed production and  
2 transmission costs among jurisdictions, which would lead to more stable rates  
3

4 Q. DOES DR. PAVLOVIC'S PROPOSAL TO BASE THE 1 CP ALLOCATOR ON THE  
5 AVERAGE OF THE ANNUAL HOURLY PEAK LOADS IN THREE HISTORICAL YEARS  
6 MITIGATE THE STABILITY PROBLEM WITH THE 1 CP METHOD?

7 A. The use of three data points does help, but the data set is still very limited.  
8 Moreover, I believe Dr. Pavlovic's approach introduces other problems  
9 stemming from its over-reliance on historical data that are important for the  
10 Commission to consider.  
11

12 Q. PLEASE EXPLAIN.

13 A. As I explained previously, the hourly system peak load in a given year may be  
14 affected by many factors that may not be repeated in subsequent years. For  
15 example, NSPM's system peak hourly load was 8,049 MW in 2012, and is  
16 projected to be 7,193 MW in 2013. Such a marked change between actual and  
17 projected loads from one year to the next casts doubt on the advisability of using  
18 unadjusted historical peak loads, such as Dr. Pavlovic suggests. The use of  
19 forecasted peak loads, as the Company proposes, helps to normalize the data, or  
20 "scrub out" some of the non-representative variation embedded in the hourly  
21 peak load during a given historical year.  
22

23 Further, Dr. Pavlovic's proposal to use historical data entails a problematic trade-  
24 off. Using a greater number of historical years to derive the allocator may help  
25 to stabilize the results over time, but it also necessitates an increasing reliance on  
26 stale data. As Ms. Heuer explains in her Rebuttal Testimony, the Company  
27 recently lost two of its largest customers, Ford Motor Company and Verso Paper

1 Corporation. The loss of these two customers reduced sales to the Minnesota  
2 Large Commercial and Industrial class by 4.5 percent in 2012 and by another 1.7  
3 percent in 2013. We have also experienced the loss of wholesale customers.  
4 The reliance on historical peak loads back to 2010, which excludes known  
5 changes, fails to capture the impact of this significant loss of large loads on the  
6 relative loads among jurisdictions.

7  
8 In summary, using three years of historical data entails drawbacks that more than  
9 offset any benefits in terms of more stable results.

10  
11 Q. YOU HAVE EXPLAINED THE DIFFICULTIES WITH DR. PAVLOVIC'S PROPOSAL IN  
12 TERMS OF ENSURING CONSISTENT ALLOCATIONS OVER TIME. CAN YOU PROVIDE  
13 ANY EMPIRICAL EVIDENCE TO SUPPORT THIS CONCLUSION?

14 A. Yes. On page 5 of Exhibit \_\_\_\_ (SBB-1), Schedule 2, I compare the results over  
15 time from using the 1 CP Method and the 12 CP Method. I also include the  
16 Relative LOLP Method as a point of reference. These results cover the historical  
17 years 2007 through 2012, and the forecasted 2013 test year. For each year, I  
18 derive the percentage of costs that would be allocated to the North Dakota retail  
19 jurisdiction. To compare the stability over time of each allocation method, I  
20 provide three metrics: (1) the absolute difference between the lowest and highest  
21 values from 2007 through 2013; (2) the percentage difference between the  
22 average and lowest values; and (3) the percentage difference between the average  
23 and highest values.

24  
25 This analysis indicates that both the 12 CP Method and Relative LOLP Method  
26 yield allocations to the North Dakota retail jurisdiction that are significantly more  
27 stable over time than the results from using the 1 CP Method. For example, the

1 absolute difference between the lowest and highest percentage allocation to  
2 North Dakota is 1.71 percentage points for the 1 CP Method, 0.65 percentage  
3 points for the 12 CP Method, and 0.59 percentage points for the Relative LOLP  
4 Method. These metrics demonstrate that the 1 CP Method yields much less  
5 stable results.

6  
7 Q. WHAT DO YOU CONCLUDE FROM YOUR ASSESSMENT OF THE 1 CP METHOD AND  
8 12 CP METHOD BASED ON THE COMMISSION'S THIRD CRITERION?

9 A. I conclude that the 12 CP Method meets the Commission's criterion, while the 1  
10 CP Method fails to produce stable results over time.

## 11 12 VI. SUMMARY AND RECOMMENDATIONS

13  
14 Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

15 A. The Company believes that its proposed method of allocating fixed production  
16 and transmission costs, the 12 CP Method, is a more reasonable allocation  
17 method than Dr. Pavlovic's proposed 1 CP Method. We reached this conclusion  
18 by applying the Commission's established evaluation criteria to both methods.

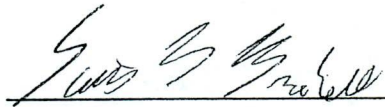
19  
20 The Company recognizes that, above all else, an allocator should properly reflect  
21 cost causality. However, as the Commission has recognized, the consistency of  
22 allocators among jurisdictions is also a very important criterion. As I have  
23 demonstrated, the 12 CP Method is more effective than the 1 CP Method in  
24 terms of accurately reflecting the costs imposed by the various NSPM  
25 jurisdictions and ensuring the long-term stability of the resulting allocations. The  
26 12 CP Method is also the method approved in all NSPM jurisdictions, which  
27 results in the equitable ratemaking treatment of prudently incurred costs.

1 STATE OF NORTH DAKOTA  
2 BEFORE THE  
3 PUBLIC SERVICE COMMISSION  
4

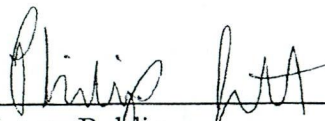
5  
6 In the Matter of the Application of Northern )  
7 States Power Company, a Minnesota Corporation )  
8 For Authority to Increase Rates for Electric Service ) Case No. PU-12-813  
9 in North Dakota )

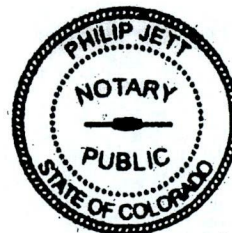
10  
11  
12  
13 **AFFIDAVIT OF**  
14 **Scott B. Brockett**  
15

16  
17 I, the undersigned, being duly sworn, depose and say that the foregoing is  
18 the Rebuttal Testimony of the undersigned, and that such Rebuttal Testimony and  
19 the exhibits or schedules sponsored by me to the best of my knowledge,  
20 information and belief, are true, correct, accurate and complete, and I hereby adopt  
21 said testimony as if given by me in formal hearing, under oath.  
22

23  
24   
25 \_\_\_\_\_  
26 Scott B. Brockett  
27

28  
29  
30 Subscribed and sworn to before me, this 6<sup>th</sup> day of August, 2013.  
31

32   
33 \_\_\_\_\_  
34 Notary Public  
35 My Commission Expires: 12/17/14  
36



My Commission Expires Dec. 17, 2014

## Scott Brockett

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**Experience**      2008-Present                      Xcel Energy Services, Inc                      Denver, Colorado  
**Director, Regulatory Administration and Compliance**

- Assist in coordinating regulatory filings of Public Service Company of Colorado.
- Manage pricing function for Public Service of Colorado electric, gas and steam departments.
- Provide economic and financial analyses supporting Xcel Energy regulatory policy development.

2004-2008                      Xcel Energy Services, Inc.                      Denver, Colorado  
**Manager, Pricing and Planning**

1999-2004                      Consumers Energy                      Jackson, MI  
**Supervisor, Pricing and Revenue Forecasting**

1982-1999                      Minnesota Department of                      St. Paul, MN  
Public Service  
**Analyst, Supervisor, Manager, Assistant Commissioner**

**Education**      1980                      Otterbein College                      Westerville, Ohio  
**Bachelor of Arts in English and Economics**

1981                      Miami University                      Oxford, Ohio <b>Masters of Arts in Economics</b>
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NSPM ALLOCATION TO NORTH DAKOTA RETAIL BEFORE TRANSMISSION LOSS MULTIPLIER

2013 PROJECTED

Month	ND CP	Total CP	Monthly 2014 LOLP	Monthly Share of Total Annual LOLP	ND % 2014 LOLP	ND % 1 CP	ND % 12 CP
January	396,111	5,489,051	0.9000%	19.9557%	1.4401%		
February	400,990	5,342,866	0.0500%	1.1086%	0.0832%		
March	344,834	5,066,690	0.1600%	3.5477%	0.2415%		
April	316,381	4,749,043	0.1000%	2.2173%	0.1477%		
May	305,174	6,034,402	0.2000%	4.4346%	0.2243%		
June	366,900	7,175,000	0.6000%	13.3038%	0.6803%		
July	345,220	7,177,763	0.4700%	10.4213%	0.5012%		
August	409,827	7,192,536	0.4100%	9.0909%	0.5180%		
September	403,276	6,826,072	0.6400%	14.1907%	0.8384%		
October	348,717	5,277,052	0.1400%	3.1042%	0.2051%		
November	370,703	5,250,149	0.4100%	9.0909%	0.6419%		
December	434,187	5,565,758	0.4300%	9.5344%	0.7438%		
Total	4,442,320	71,146,382	4.51%	100.00%	6.27%	5.70%	6.24%

ACTUAL 2012

Month	ND CP	Total CP	Monthly 2014 LOLP	Monthly Share of Total Annual LOLP	ND % 2014 LOLP	ND % 1 CP	ND % 12 CP
January	406,845	5,380,244	0.9000%	19.9557%	1.5090%		
February	328,842	5,012,963	0.0500%	1.1086%	0.0727%		
March	307,812	5,048,463	0.1600%	3.5477%	0.2163%		
April	288,840	4,724,631	0.1000%	2.2173%	0.1356%		
May	361,845	6,083,860	0.2000%	4.4346%	0.2638%		
June	388,794	7,409,552	0.6000%	13.3038%	0.6981%		
July	437,821	8,049,030	0.4700%	10.4213%	0.5665%		
August	368,824	7,433,426	0.4100%	9.0909%	0.4511%		
September	357,795	7,004,533	0.6400%	14.1907%	0.7249%		
October	283,858	4,911,463	0.1400%	3.1042%	0.1794%		
November	359,864	5,210,122	0.4100%	9.0909%	0.6279%		
December	384,820	5,380,659	0.4300%	9.5344%	0.6819%		
Total	4,275,960	71,648,946	4.51%	100.00%	6.13%	5.44%	5.97%

ACTUAL 2011

Month	ND CP	Total CP	Monthly 2014 LOLP	Monthly Share of Total Annual LOLP	ND % 2014 LOLP	ND % 1 CP	ND % 12 CP
January	403,752	5,577,000	0.9000%	19.9557%	1.4447%		
February	389,716	5,480,460	0.0500%	1.1086%	0.0788%		
March	380,715	5,198,225	0.1600%	3.5477%	0.2598%		
April	312,764	4,786,934	0.1000%	2.2173%	0.1449%		
May	264,818	5,233,104	0.2000%	4.4346%	0.2244%		
June	328,814	7,690,340	0.6000%	13.3038%	0.5688%		
July	379,852	8,079,940	0.4700%	10.4213%	0.4899%		
August	433,870	7,150,333	0.4100%	9.0909%	0.5516%		
September	373,848	7,360,249	0.6400%	14.1907%	0.7208%		
October	349,880	5,464,631	0.1400%	3.1042%	0.1988%		
November	349,875	5,165,772	0.4100%	9.0909%	0.6157%		
December	374,829	5,389,550	0.4300%	9.5344%	0.6631%		
Total	4,342,733	72,576,538	4.51%	100.00%	5.96%	4.70%	5.98%

NSPM ALLOCATION TO NORTH DAKOTA RETAIL BEFORE TRANSMISSION LOSS MULTIPLIER - Cont'd

**ACTUAL 2010**

Month	ND CP	Total CP	Monthly 2014 LOLP	Monthly Share of Total Annual LOLP	ND % 2014 LOLP	ND % 1 CP	ND % 12 CP
January	390,763	5,612,500	0.9000%	19.9557%	1.3894%		
February	374,773	5,343,505	0.0500%	1.1086%	0.0778%		
March	325,779	4,899,396	0.1600%	3.5477%	0.2359%		
April	284,833	4,873,429	0.1000%	2.2173%	0.1296%		
May	295,837	7,203,063	0.2000%	4.4346%	0.1821%		
June	325,812	7,093,502	0.6000%	13.3038%	0.6111%		
July	351,805	7,501,030	0.4700%	10.4213%	0.4888%		
August	444,784	7,749,212	0.4100%	9.0909%	0.5218%		
September	308,824	5,734,420	0.6400%	14.1907%	0.7642%		
October	321,859	5,292,402	0.1400%	3.1042%	0.1888%		
November	379,861	5,542,512	0.4100%	9.0909%	0.6231%		
December	404,897	5,684,921	0.4300%	9.5344%	0.6791%		
Total	4,209,827	72,529,892	4.51%	100.00%	5.89%	5.74%	5.80%

**ACTUAL 2009**

Month	ND CP	Total CP	Monthly 2014 LOLP	Monthly Share of Total Annual LOLP	ND % 2014 LOLP	ND % 1 CP	ND % 12 CP
January	418,726	5,708,296	0.9000%	19.9557%	1.4638%		
February	391,553	5,463,812	0.0500%	1.1086%	0.0794%		
March	371,808	5,191,854	0.1600%	3.5477%	0.2541%		
April	306,750	4,737,260	0.1000%	2.2173%	0.1436%		
May	282,814	5,989,217	0.2000%	4.4346%	0.2094%		
June	287,840	7,151,025	0.6000%	13.3038%	0.5355%		
July	311,820	6,325,750	0.4700%	10.4213%	0.5137%		
August	329,854	6,916,297	0.4100%	9.0909%	0.4336%		
September	356,710	6,036,342	0.6400%	14.1907%	0.8386%		
October	288,861	4,891,381	0.1400%	3.1042%	0.1833%		
November	326,851	5,133,237	0.4100%	9.0909%	0.5788%		
December	420,779	5,801,180	0.4300%	9.5344%	0.6916%		
Total	4,094,366	69,345,651	4.51%	100.00%	5.93%	4.03%	5.90%

**ACTUAL 2008**

Month	ND CP	Total CP	Monthly 2014 LOLP	Monthly Share of Total Annual LOLP	ND % 2014 LOLP	ND % 1 CP	ND % 12 CP
January	408,720	5,764,620	0.9000%	19.9557%	1.4149%		
February	394,733	5,648,748	0.0500%	1.1086%	0.0775%		
March	376,786	5,274,853	0.1600%	3.5477%	0.2534%		
April	283,768	4,887,814	0.1000%	2.2173%	0.1287%		
May	277,784	4,956,349	0.2000%	4.4346%	0.2485%		
June	355,821	6,785,987	0.6000%	13.3038%	0.6976%		
July	310,834	7,345,018	0.4700%	10.4213%	0.4410%		
August	400,808	7,203,196	0.4100%	9.0909%	0.5058%		
September	284,815	6,163,576	0.6400%	14.1907%	0.6557%		
October	278,866	5,006,619	0.1400%	3.1042%	0.1729%		
November	349,942	5,408,842	0.4100%	9.0909%	0.5882%		
December	400,867	5,904,603	0.4300%	9.5344%	0.6473%		
Total	4,123,744	70,350,225	4.51%	100.00%	5.83%	4.23%	5.86%

**ACTUAL 2007**

Month	ND CP	Total CP	Monthly 2014 LOLP	Monthly Share of Total Annual LOLP	ND % 2014 LOLP	ND % 1 CP	ND % 12 CP
January	395,660	5,480,717	0.9000%	19.9557%	1.4406%		
February	377,656	5,562,375	0.0500%	1.1086%	0.0753%		
March	336,745	5,198,919	0.1600%	3.5477%	0.2298%		
April	321,690	4,959,894	0.1000%	2.2173%	0.1438%		
May	297,770	6,176,566	0.2000%	4.4346%	0.2138%		
June	295,776	7,349,376	0.6000%	13.3038%	0.5354%		
July	300,778	7,453,297	0.4700%	10.4213%	0.4206%		
August	378,794	7,353,657	0.4100%	9.0909%	0.4683%		
September	372,815	7,446,248	0.6400%	14.1907%	0.7105%		
October	280,804	5,681,325	0.1400%	3.1042%	0.1534%		
November	389,833	5,625,562	0.4100%	9.0909%	0.6300%		
December	387,719	5,687,435	0.4300%	9.5344%	0.6500%		
Total	4,136,040	73,975,371	4.51%	100.00%	5.67%	4.04%	5.59%

**NSPM ALLOCATION TO NORTH DAKOTA RETAIL AFTER TRANSMISSION LOSS MULTIPLIER**

TLM: 0.9294 **2013 PROJECTED**

Month	ND CP	Total CP	Monthly 2014 LOLP	Monthly Share of Total Annual LOLP	ND % 2014 LOLP	ND % 1 CP	ND % 12 CP
January	368,146	5,288,907	0.9000%	19.9557%	1.3891%		
February	372,680	5,148,052	0.0500%	1.1086%	0.0803%		
March	320,489	4,881,946	0.1600%	3.5477%	0.2329%		
April	294,045	4,575,881	0.1000%	2.2173%	0.1425%		
May	283,629	5,814,373	0.2000%	4.4346%	0.2163%		
June	340,997	6,913,382	0.6000%	13.3038%	0.6562%		
July	320,847	6,916,044	0.4700%	10.4213%	0.4835%		
August	380,893	6,930,278	0.4100%	9.0909%	0.4996%		
September	374,805	6,577,177	0.6400%	14.1907%	0.8087%		
October	324,098	5,084,638	0.1400%	3.1042%	0.1979%		
November	344,531	5,058,716	0.4100%	9.0909%	0.6191%		
December	403,533	5,362,817	0.4300%	9.5344%	0.7174%		
<b>Total</b>	<b>4,128,692</b>	<b>68,552,209</b>	<b>4.51%</b>	<b>100.00%</b>	<b>6.04%</b>	<b>5.50%</b>	<b>6.02%</b>

TLM: 0.9294 **ACTUAL 2012**

Month	ND CP	Total CP	Monthly 2014 LOLP	Monthly Share of Total Annual LOLP	ND % 2014 LOLP	ND % 1 CP	ND % 12 CP
January	378,122	5,184,624	0.9000%	19.9557%	1.4554%		
February	305,626	4,830,697	0.0500%	1.1086%	0.0701%		
March	286,080	4,864,906	0.1600%	3.5477%	0.2086%		
April	268,448	4,552,848	0.1000%	2.2173%	0.1307%		
May	336,299	5,862,657	0.2000%	4.4346%	0.2544%		
June	361,345	7,140,148	0.6000%	13.3038%	0.6733%		
July	406,911	7,756,376	0.4700%	10.4213%	0.5467%		
August	342,785	7,163,154	0.4100%	9.0909%	0.4350%		
September	332,535	6,749,855	0.6400%	14.1907%	0.6991%		
October	263,818	4,732,887	0.1400%	3.1042%	0.1730%		
November	334,458	5,020,687	0.4100%	9.0909%	0.6056%		
December	357,652	5,185,024	0.4300%	9.5344%	0.6577%		
<b>Total</b>	<b>3,974,077</b>	<b>69,043,864</b>	<b>4.51%</b>	<b>100.00%</b>	<b>5.91%</b>	<b>5.25%</b>	<b>5.76%</b>

TLM: 0.9283 **ACTUAL 2011**

Month	ND CP	Total CP	Monthly 2014 LOLP	Monthly Share of Total Annual LOLP	ND % 2014 LOLP	ND % 1 CP	ND % 12 CP
January	374,803	5,386,454	0.9000%	19.9557%	1.3886%		
February	361,773	5,293,213	0.0500%	1.1086%	0.0758%		
March	353,418	5,020,621	0.1600%	3.5477%	0.2497%		
April	290,339	4,623,382	0.1000%	2.2173%	0.1392%		
May	245,831	5,054,308	0.2000%	4.4346%	0.2157%		
June	305,238	7,427,589	0.6000%	13.3038%	0.5467%		
July	352,617	7,803,878	0.4700%	10.4213%	0.4709%		
August	402,762	6,906,032	0.4100%	9.0909%	0.5302%		
September	347,043	7,108,776	0.6400%	14.1907%	0.6928%		
October	324,794	5,277,925	0.1400%	3.1042%	0.1910%		
November	324,789	4,989,277	0.4100%	9.0909%	0.5918%		
December	347,954	5,205,409	0.4300%	9.5344%	0.6373%		
<b>Total</b>	<b>4,031,359</b>	<b>70,096,864</b>	<b>4.51%</b>	<b>100.00%</b>	<b>5.73%</b>	<b>4.52%</b>	<b>5.75%</b>

**NSPM ALLOCATION TO NORTH DAKOTA RETAIL AFTER TRANSMISSION LOSS MULTIPLIER - Cont'd**

TLM: 0.9289 **ACTUAL 2010**

Month	ND CP	Total CP	Monthly 2014 LOLP	Monthly Share of Total Annual LOLP	ND % 2014 LOLP	ND % 1 CP	ND % 12 CP
January	362,980	5,425,039	0.9000%	19.9557%	1.3352%		
February	348,127	5,165,029	0.0500%	1.1086%	0.0747%		
March	302,616	4,735,753	0.1600%	3.5477%	0.2267%		
April	264,581	4,710,654	0.1000%	2.2173%	0.1245%		
May	274,803	6,962,477	0.2000%	4.4346%	0.1750%		
June	302,647	6,856,575	0.6000%	13.3038%	0.5872%		
July	326,792	7,250,491	0.4700%	10.4213%	0.4697%		
August	413,160	7,490,384	0.4100%	9.0909%	0.5014%		
September	286,867	5,542,887	0.6400%	14.1907%	0.7344%		
October	298,975	5,115,633	0.1400%	3.1042%	0.1814%		
November	352,853	5,357,389	0.4100%	9.0909%	0.5988%		
December	376,109	5,495,041	0.4300%	9.5344%	0.6526%		
<b>Total</b>	<b>3,910,508</b>	<b>70,107,353</b>	<b>4.51%</b>	<b>100.00%</b>	<b>5.66%</b>	<b>5.52%</b>	<b>5.58%</b>

TLM: 0.9279 **ACTUAL 2009**

Month	ND CP	Total CP	Monthly 2014 LOLP	Monthly Share of Total Annual LOLP	ND % 2014 LOLP	ND % 1 CP	ND % 12 CP
January	388,536	5,511,222	0.9000%	19.9557%	1.4069%		
February	363,322	5,275,178	0.0500%	1.1086%	0.0764%		
March	345,001	5,012,610	0.1600%	3.5477%	0.2442%		
April	284,633	4,573,710	0.1000%	2.2173%	0.1380%		
May	262,423	5,782,444	0.2000%	4.4346%	0.2013%		
June	267,087	6,904,142	0.6000%	13.3038%	0.5147%		
July	289,338	6,107,359	0.4700%	10.4213%	0.4937%		
August	306,072	6,677,518	0.4100%	9.0909%	0.4167%		
September	330,991	5,827,942	0.6400%	14.1907%	0.8059%		
October	268,034	4,722,510	0.1400%	3.1042%	0.1762%		
November	303,285	4,956,016	0.4100%	9.0909%	0.5563%		
December	390,441	5,600,899	0.4300%	9.5344%	0.6646%		
<b>Total</b>	<b>3,799,162</b>	<b>66,951,550</b>	<b>4.51%</b>	<b>100.00%</b>	<b>5.69%</b>	<b>3.87%</b>	<b>5.67%</b>

TLM: 0.9279 **ACTUAL 2008**

Month	ND CP	Total CP	Monthly 2014 LOLP	Monthly Share of Total Annual LOLP	ND % 2014 LOLP	ND % 1 CP	ND % 12 CP
January	379,251	5,534,248	0.9000%	19.9557%	1.3675%		
February	366,273	5,423,007	0.0500%	1.1086%	0.0749%		
March	349,620	5,064,054	0.1600%	3.5477%	0.2449%		
April	263,308	4,692,482	0.1000%	2.2173%	0.1244%		
May	257,756	4,758,278	0.2000%	4.4346%	0.2402%		
June	330,166	6,514,799	0.6000%	13.3038%	0.6742%		
July	288,423	7,051,489	0.4700%	10.4213%	0.4263%		
August	371,910	6,915,335	0.4100%	9.0909%	0.4889%		
September	264,280	5,917,261	0.6400%	14.1907%	0.6338%		
October	258,760	4,806,539	0.1400%	3.1042%	0.1671%		
November	324,711	5,192,688	0.4100%	9.0909%	0.5685%		
December	371,964	5,668,637	0.4300%	9.5344%	0.6256%		
<b>Total</b>	<b>3,826,422</b>	<b>67,538,818</b>	<b>4.51%</b>	<b>100.00%</b>	<b>5.64%</b>	<b>4.09%</b>	<b>5.67%</b>

TLM: 0.985 **ACTUAL 2007**

Month	ND CP	Total CP	Monthly 2014 LOLP	Monthly Share of Total Annual LOLP	ND % 2014 LOLP	ND % 1 CP	ND % 12 CP
January	389,725	5,305,669	0.9000%	19.9557%	1.4658%		
February	371,991	5,384,719	0.0500%	1.1086%	0.0766%		
March	331,694	5,032,872	0.1600%	3.5477%	0.2338%		
April	316,865	4,801,481	0.1000%	2.2173%	0.1463%		
May	293,303	5,979,294	0.2000%	4.4346%	0.2175%		
June	291,339	7,114,645	0.6000%	13.3038%	0.5448%		
July	296,266	7,215,247	0.4700%	10.4213%	0.4279%		
August	373,112	7,118,790	0.4100%	9.0909%	0.4765%		
September	367,223	7,208,423	0.6400%	14.1907%	0.7229%		
October	276,592	5,499,870	0.1400%	3.1042%	0.1561%		
November	383,986	5,445,888	0.4100%	9.0909%	0.6410%		
December	381,903	5,505,785	0.4300%	9.5344%	0.6613%		
<b>Total</b>	<b>4,073,999</b>	<b>71,612,683</b>	<b>4.51%</b>	<b>100.00%</b>	<b>5.77%</b>	<b>4.11%</b>	<b>5.69%</b>

**NSPM ALLOCATION TO NORTH DAKOTA RETAIL BEFORE TRANSMISSION LOSS MULTIPLIER**

Line No.	Year	ND % 1 CP	ND % 12 CP	ND % 2014 LOLP
1				
2				
3	2007	4.04%	5.59%	5.67%
4	2008	4.23%	5.86%	5.83%
5	2009	4.03%	5.90%	5.93%
6	2010	5.74%	5.80%	5.89%
7	2011	4.70%	5.98%	5.96%
8	2012	5.44%	5.97%	6.13%
9	2013	5.70%	6.24%	6.27%
10				
11	Simple Average	4.84%	5.91%	5.95%
12				
13	Range (High-Low)	1.71%	0.65%	0.59%
14				
15	Maximum as % Above Average	18.6%	5.7%	5.2%
16				
17				
18	Minimum as % Below Average	-16.8%	-5.4%	-4.7%
19				
20				
21				

**NORTH DAKOTA ALLOCATION AFTER TRANSMISSION LOSS MULTIPLIERS**

Line No.	Year	ND % 1 CP	ND % 12 CP	ND % 2014 LOLP
22				
23				
24				
25				
26				
27	2007	4.11%	5.69%	5.77%
28	2008	4.09%	5.67%	5.64%
29	2009	3.87%	5.67%	5.69%
30	2010	5.52%	5.58%	5.66%
31	2011	4.52%	5.75%	5.73%
32	2012	5.25%	5.76%	5.91%
33	2013	5.50%	6.02%	6.04%
34				
35	Simple Average	4.69%	5.73%	5.78%
36				
37	Range (High-Low)	1.65%	0.44%	0.41%
38				
39	Maximum as % Above Average	17.6%	5.0%	4.6%
40				
41				
42	Minimum as % Below Average	-17.5%	-2.7%	-2.5%
43				