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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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND TITLE.

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

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

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

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I will respond to the Direct Testimony of North Dakota Public Service Commission Advocacy Staff Witness Dr. Karl R. Pavlovic. More specifically, I will respond to Dr. Pavlovic's recommendation regarding the allocation of production and transmission costs to the North Dakota retail jurisdiction. I will explain why the Company believes the 12 CP Method results in a more equitable and stable allocation of costs among jurisdictions than the 1 CP Method that Dr. Pavlovic proposes.

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

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

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

- Does it reasonably reflect the incremental cost caused by each jurisdiction?
- Is it consistently applied among each of the Company's jurisdictions?
- Is it understandable, inexpensive to administer, and does not result in large swings in jurisdictional cost responsibility over time?[1]

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

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

[1] *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.

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

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

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

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

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

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

Similarly, our transmission system is designed to economically meet both system and local demands. The 1 CP Method focuses *only* on total system needs, while the 12 CP Method recognizes our need to serve the monthly peak demands in each jurisdiction.

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

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

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

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

Q. WHICH ALLOCATION METHOD PRODUCES MORE STABLE RESULTS?

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

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

II. COST CAUSALITY – PRODUCTION FUNCTION

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

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

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.

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

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

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

Q. PLEASE ELABORATE ON THE NARUC DISCUSSION.

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

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

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

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

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

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

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

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

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

As I describe below, by considering loads during all 12 months, the 12 CP Method recognizes that *loads in all months* contribute to the levels of the Company's fixed production costs. In contrast, the 1 CP Method assumes that loads during the *single system peak hour* of the 8,760 hours in a year entirely drive the level of a utility's fixed production costs. By extension, the 1 CP Method assumes that loads in the other 8,759 hours have no bearing on the mix of resources and level of fixed production costs. This assumption ignores the dual goals that the Company balances when deciding on the total effective capacity and mix of its production plant portfolio.

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

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

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

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

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

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

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

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

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

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

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

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

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

A. While the Company certainly plans on ensuring sufficient capacity to meet summer peak loads, the drivers of generation capacity needs are not limited to these projected peaks. We plan our production system to meet our forecasted peak loads, including a targeted reserve margin to account for contingencies such as higher-than-anticipated peak demand or forced (unplanned) outages. While variations in peak loads or forced outages around their expected values may be difficult to predict, a utility has considerable flexibility in the timing of scheduled maintenance.

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

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

The salient advantage of using these probabilities is that period-specific reliability risks can be specifically identified, given projected loads, the probability of forced outages, and planned maintenance. By extension, the differences in these probabilities among periods can provide guidance on what loads truly drive a need for additional capacity. As I will explain below, the results of such an analysis for NSPM confirms the inappropriateness of assuming the reliability risks attributable to inadequate generation resources are concentrated in one hour. This analysis suggests that many different months contribute significantly to the annual probability of unserved load.

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

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

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

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

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

A. Yes. In March 2013 the Company completed a Loss of Load Probability Study to estimate the probability of unserved load due to a lack of generation resources during different periods in calendar year 2014. This study incorporates planned maintenance into the estimated availability of generation resources during various periods. This study concludes that the average hourly loss of load probabilities in the winter months of December through March are lower than, but reasonably comparable to, the loss of load probabilities during the four summer months. In other words, the probabilities of load loss during the summer and winter seasons do not vary as much as one might conclude from reviewing monthly coincident peak loads only. Moreover, as explained more fully below, an allocator based on this study more closely reflects the results of the 12 CP Method than the 1 CP Method.

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

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

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

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

Q. WHAT DO YOU CONCLUDE FROM THIS ANALYSIS?

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

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

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

A. No. I believe the 12 CP Method is better-suited to capturing the energy-related component of fixed generation costs. Even to the extent the fixed production costs are classified as capacity-related costs, the allocation of such costs based on monthly loss of load probabilities is not without difficulties. For example, the Relative LOLP Method does not address whether higher peak loads in non-summer months would be accommodated through additional generation resources, modified maintenance schedules, other initiatives, or some combination of these potential responses.

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

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

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

III. COST CAUSALITY – TRANSMISSION FUNCTION

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

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

In other words, the energy savings from reducing transmission losses do not rise to the significance of the energy savings that justify the additional capital costs of production plant. That is why – to the best of my knowledge – there has been little interest in explicitly stratifying (classifying) transmission plant into capacity- and energy-related components. However, the use of transmission plant for energy transfers is an important cost driver.

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

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

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

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

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

Q. In your judgement, what allocation method best meets the Commission's first criterion – the accurate reflection of cost causality?

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

IV. CONSISTENT APPLICATION AMONG UTILITIES

Q. Is the consistent application of allocators among jurisdictions an important consideration to the Commission?

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

Q. Is this criterion important to the Company as well?

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

Q. Different Commissions often reach different conclusions regarding the various components of a utility's test-year costs. Why should regulators be concerned about approving different jurisdictional allocators?

A. The consequences of two Commissions approving two different jurisdictional allocators are not consistent with the goal of equitable regulation, and can be distinguished from the consequences of different decisions regarding other test-year costs. Under traditional regulation, two different Commissions assessing the prudency of a given cost often reach different conclusions. For example, one Commission may decide that the utility's test-year labor costs are at appropriate levels, while another Commission may order a partial disallowance on specific grounds. Similarly, two Commissions might reach different decisions regarding the prudency of the utility's capital expenditures or its required return on equity. These different decisions and resulting financial implications to the utility are common and are consistent with the traditional goals of economic regulation, assuming both Commissions base their decisions on record evidence.

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

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

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

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

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

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

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

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

[2] 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.

nationally towards the 1 CP Method.

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

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

V. TRANSPARENCY, COST OF ADMINISTERING, AND STABILITY OF RESULTS

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

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

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

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

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

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

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

Q. PLEASE EXPLAIN.

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

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

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

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

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

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

This analysis indicates that both the 12 CP Method and Relative LOLP Method yield allocations to the North Dakota retail jurisdiction that are significantly more stable over time than the results from using the 1 CP Method. For example, the absolute difference between the lowest and highest percentage allocation to North Dakota is 1.71 percentage points for the 1 CP Method, 0.65 percentage points for the 12 CP Method, and 0.59 percentage points for the Relative LOLP Method. These metrics demonstrate that the 1 CP Method yields much less stable results.

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

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

VI. SUMMARY AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

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

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

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

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

AFFIDAVIT OF
Scott B. Brockett

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

Scott B. Brockett
Scott B. Brockett

Subscribed and sworn to before me, this 6th day of August, 2013.

Philip Jett
Notary Public
My Commission Expires: 12/17/14

PHILIP JETT
NOTARY PUBLIC
STATE OF COLORADO
My Commission Expires Dec. 17, 2014

Scott Brockett

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 Public Service | St. Paul, MN

Analyst, Supervisor, Manager, Assistant Commissioner

Education

198O | Otterbein College | Westerville, Ohio

Bachelor of Arts in English and Economics

1981 | Miami University | Oxford, Ohio

Masters of Arts in Economics

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%	0.5669%		
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%		
Total	4,128,692	68,552,209	4.51%	100.00%	6.04%	5.50%	6.02%

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%		
Total	3,974,077	69,043,864	4.51%	100.00%	5.91%	5.25%	5.76%

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%		
Total	4,031,359	70,096,864	4.51%	100.00%	5.73%	4.52%	5.75%

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%		
Total	3,910,508	70,107,353	4.51%	100.00%	5.66%	5.52%	5.58%

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%		
Total	3,799,162	66,951,550	4.51%	100.00%	5.69%	3.87%	5.67%

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%		
Total	3,826,422	67,538,818	4.51%	100.00%	5.64%	4.09%	5.67%

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%		
Total	4,073,999	71,612,683	4.51%	100.00%	5.77%	4.11%	5.69%

NSPM ALLOCATION TO NORTH DAKOTA RETAIL BEFORE TRANSMISSION LOSS MULTIPLIER

Line No.	Year	ND % 1 CP	ND % 12 CP	ND % 2014 LOLP
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%
11	Simple Average	4.84%	5.91%	5.95%
13	Range (High-Low)	1.71%	0.65%	0.59%
15–16	Maximum as % Above Average	18.6%	5.7%	5.2%
18–19	Minimum as % Below Average	-16.8%	-5.4%	-4.7%

22 **NORTH DAKOTA ALLOCATION AFTER TRANSMISSION LOSS MULTIPLIERS**

Line No.	Year	ND % 1 CP	ND % 12 CP	ND % 2014 LOLP
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%
35	Simple Average	4.69%	5.73%	5.78%
37	Range (High-Low)	1.65%	0.44%	0.41%
39–40	Maximum as % Above Average	17.6%	5.0%	4.6%
42–43	Minimum as % Below Average	-17.5%	-2.7%	-2.5%