Direct Testimony and Schedule
Steven W. Wishart

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-24-___
Exhibit___(SWW-1)

Demand Allocator

December 2, 2024

9 PU-24-376 Filed 12/02/2024 Pages: 45
Prefiled Direct Testimony and Schedules of Steven W. Wishart

Northern States Power Company

Table of Contents

Schedule

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Steven W. Wishart. I am an Assistant Vice President at Concentric Energy Advisors, Inc. (Concentric). Concentric is a management consulting firm that provides regulatory, financial, and economic advisory and litigation support services to energy and utility clients across North America. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of Northern States Power Company, a Minnesota corporation (NSP, Xcel Energy, or the Company). NSP is a wholly owned subsidiary of Xcel Energy Inc.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have worked in the energy industry for more than 20 years. Before joining Concentric in the fall of 2023, I worked at Xcel Energy for 18 years. At Xcel Energy I served as Director of Pricing and Regulatory Analytics for the Colorado jurisdiction. In that role I performed rate design, cost allocation, long term rate forecasting, and numerous other analyses in support of regulatory filings. At Xcel Energy, I also served as Director of Resource Planning and Bidding for the Midwest jurisdiction. In that role, I oversaw the long-range planning for the electric generation portfolio and conducted competitive resource acquisition processes. I hold a Bachelor of Science in Finance and a Master of Science in Resource Economics from the University of Arizona and have completed all the coursework for a Ph.D. in Applied Economics from the

University of Minnesota. Please see Exhibit___(SWW-1), Schedule 1, Statement of Qualifications.

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

A. The purpose of my testimony is to support the Company's demand allocator, which is used to allocate the cost of production and transmission between North Dakota and the other states served by the Company. Specifically, I provide an overview of cost allocation and support for the continued use of the 12 Coincident Peak (12 CP) methodology. I introduce cost allocation, explain the 12 CP allocator (and a couple of the alternatives) and discuss appropriateness of the 12 CP allocator given criteria previously set forth by the Commission and in light of a previous study that considered the issue.

Q. YOU REFERRED TO THE CONTINUED USE OF THE 12 CP ALLOCATOR. IS THAT SAME DEMAND ALLOCATOR USED IN THE COMPANY'S OTHER JURISDICTIONS?

A. Yes. The 12 CP allocator is used by North Dakota, South Dakota, and Minnesota, which is one important advantage of it as a methodology for reasons that I will discuss further below. Retaining the ability to use a consistent allocator across all three jurisdictions is a key component for the just and reasonable allocation of costs. As I demonstrate in my testimony, there has been no material change of circumstances that justifies a change in allocator and there is no material reason for the Commission to deviate from this use of a consistent allocation methodology across all three states.

Q. HOW WAS THE CURRENT USE OF THE 12 CP DEMAND ALLOCATOR ESTABLISHED?

A. The 12 CP demand allocator has been in use since at least 1993. The issue of selecting the proper demand allocator was last litigated in Case No. PU-12-813, which was an electric rate case filed in December 2012 (2012 Rate Case). In that case, the Company proposed to continue using the 12 CP methodology. Staff witness Karl Pavlovic recommended that production and transmission costs be allocated based on the single system coincident peak demand (1CP).

To resolve the conflicting recommendations, the February 2014 Amended Settlement Agreement in the 2012 Rate Case included a provision that required a third-party study of jurisdictional demand allocators (the 2015 Study). The 2015 Study was to analyze a number of methodologies and propose a recommendation on the one or more methodologies that reasonably represents cost causation on the Company's production and transmission costs.

Q. WHAT WERE THE RESULTS OF THE 2015 STUDY?

A. The 2015 Study observed that there were several alternative methodologies that used both peak demand and measures of total energy consumed or that used several demand values that appear to be appropriate based on the principle of cost causality. The 2015 Study found that the use of 12 CP was appropriate and did not find compelling reasons to change the allocation method used in North Dakota.

After the 2015 Study was completed, the parties reached agreement on several issues, including the demand allocator. The First Revised Negotiated Agreement in Case No. PU-12-813, filed on February 22, 2016, established a rebuttable presumption that the 12 CP jurisdictional allocation method is appropriate for allocating applicable system costs between North Dakota, South Dakota, and Minnesota. The agreement also specified that this provision will expire December 31, 2025.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE APPROPRIATE DEMAND ALLOCATOR FOR THIS PROCEEDING.

A. I conclude that customer use and the NSP System have not changed in such a drastic way as to warrant a departure from the established 12 CP methodology. The 12 CP approach is more appropriate than the use of other allocation methods available as the 12 CP allocator is most reflective of both the current planning process and how MISO charges for transmission services. 12 CP is also more stable and predictable than many different approaches, including the 1 CP allocator that was proposed by Staff's witness in the 2012 Rate Case. Overall, the 12 CP approach has been in place for many years and continues to meet the Commission's criteria for selection of allocation methodologies and will ensure fair and accurate recovery of all Commission approved costs.

II. OVERVIEW OF COST ALLOCATION

Q. PLEASE PROVIDE AN OVERVIEW OF THE COST ALLOCATION PROCESS.

A. Utilities regularly find the need to split some of their expenses and rate base assets among various customer groups. The divisions may be between retail and wholesale customers, various customer classes such as residential and commercial, or, as in this circumstance, between states. The cost allocation process is commonly described as having three steps: 1) Functionalization, 2) Classification, and 3) Allocation.

The functionalization step involves assigning expenses and assets to categories representing the various operational segments of a utility. For an electric utility the functional classes commonly include: production, transmission, fuel, purchased energy, substations, primary distribution, secondary distribution, transformers, service laterals, meters, meter reading, and customer service. Expenses and assets that do not fit within a functional class, such as common plant and administrative costs, are spread across all the functional categories typically using the category's net plant investments or some other measure of the function's relative size.

The second step in the process is to classify the functionalized costs as being associated with three broad categories that are believed to give rise to those costs: demand, energy, and customers. In some cases, a functional cost category is recognized to be driven by multiple classification categories. One example of this is fixed production costs. The cost of power plants is commonly recognized to be driven by both peak demand and overall energy consumption. Many states, including North Dakota,[1] perform calculations to stratify fixed production costs between the demand and energy classifications. In other words, these calculations attempt to determine what portion of a utility's plant was built to fulfill its capacity needs, and what portion was built to fulfill its energy needs, when the plant in total contributes to both.

The third step is the actual allocation of assets and expenses across the various customer groups. For each functional category a specific allocation methodology is selected, generally based on how that category was classified.

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[1] Direct Testimony Michael A. Peppin, Schedule 2, page 4. Norther States Power Company, Case No. PU-12-813.

Some assets can be directly assigned to a customer group, such as the cost of streetlights which should be directly assigned to the street lighting class of customers and not included in the costs assigned to any other customer group. However, most functional cost categories are allocated across all customer groups based on a formulaic methodology that reflects a fair apportionment of those costs.

Q. HOW ARE ALLOCATION METHODOLOGIES SELECTED?

A. I am not aware of any universally accepted approach to selecting a specific cost allocation methodology. The Electric Utility Cost Allocation Manual published by the National Association of Regulatory Utility Commissioners (NARUC) recognizes that "no single costing methodology will be superior to any other, and that the choice of methodology will depend on the unique circumstances of each utility."[2] Previously, the North Dakota Commission has laid out three criteria that they used to select a specific cost allocation methodology:

> "The standards we look to in determining an appropriate allocation factor are fair cost apportionment, consistency among jurisdictions and administrative ease"[3]

Q. WHAT IS THE 12 CP ALLOCATION METHODOLOGY?

A. The "12" in 12 CP refers to the twelve months of a calendar year. The "CP," is short for "coincident peak" as I noted when I first defined the term above in my introduction. The coincident peak for the Company in North Dakota, South Dakota, and Minnesota in each month is the hour when the aggregate demand on the NSP System from those three jurisdictions is highest. This may or may

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[2] Electric Utility Cost Allocation Manual, January 1992. National Association of Regulatory Utility Commissioner, at 22.

[3] Northern States Power Company, Electric Rates, PU-400-92-399; ORDER ON RECONSIDERATION Dated April 7, 1993 at 2.

not be the hour when the load is highest in the individual jurisdictions. To calculate the 12 CP allocator, the Company determines the coincident peak hour for each month of the year in question and finds the demand in each jurisdiction during those peak hours. Then, the total demand for the peak hours of the year is summed or averaged as are the contributing demand from each jurisdiction. The allocation percentage for each jurisdiction is found by dividing its twelve-month total by the overall twelve-month total. Figure 1 below is an illustrative example taken from the 2015 Study.

Figure 1
12 CP Example from 2015 Study

Example

2013 Actual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
MN Jur.	4,811,712	4,594,868	4,372,895	4,154,462	4,753,833	6,075,120	7,050,247	7,278,146	6,437,556	4,487,880	4,546,014	4,953,425	63,516,159
ND Jur.	418,807	409,815	353,834	349,803	310,836	399,804	448,869	419,851	330,804	293,855	368,858	429,792	4,534,927
SD Jur.	321,600	302,768	277,994	248,528	360,896	415,909	460,913	487,924	461,910	294,912	297,884	333,774	4,265,013
NSPM Co.	5,552,120	5,307,451	5,004,723	4,752,793	5,425,565	6,890,833	7,960,030	8,185,922	7,230,270	5,076,647	5,212,756	5,716,991	72,316,100

Then the 12CP calculation is as follows:

12CP	Sum of Mo. Peaks	Trans. Loss Adjustment	Adj. Sum of S, W Peaks	Allocation Factor
MN Jur.	63,516,159	95.800%	60,848,480	87.763%
ND Jur.	4,534,927	93.410%	4,236,076	6.110%
SD Jur.	4,265,013	99.610%	4,248,380	6.128%
NSPM Co.	72,316,100		69,332,936	100.000%

Q. WHAT ARE ALTERNATIVES TO 12 CP?

A. There are multiple recognized allocation methodologies and in the interest of brevity I will not describe them all. The 2015 Study provides an overview of 12 different allocators. Two of the alternatives that I understand have been discussed as possibilities for use in North Dakota are the 1 CP method and the four-month coincident peak (4 CP) method. The 1 CP method, as the name suggests, is based on a single coincident peak. The single hour in a year with the highest aggregate demand is determined and costs are allocated based on each jurisdiction's contribution to that coincident peak, which is expressed in a percentage. Using the illustrative example from Figure 1 above, a 1 CP allocator would be based on just the single hour from August. With 4 CP, the allocator is based on the coincident peaks in four months of the year. The four months used are those that have the highest coincident peak hours. In Figure 1 above, the four months would be June through September. The total demand from the four peak hours are summed up as are the contributions to that demand in each of the four hours from each jurisdiction. The allocator is then expressed as the percentage contribution from each jurisdiction to the total.

Q. DOES THE 12 CP METHOD SATISFY THE COMMISSION'S CRITERIA FOR SELECTING AN ALLOCATOR??

A. Yes. I will discuss each of the criteria in greater depth in the section below, but it does. I believe that the 12 CP demand allocator is a fair way to allocate production and transmission costs across the states served by the Company. By using load data from each month to apportion costs, the method recognizes that customers in each state use production and transmission resources year-round. I believe that the concept of paying for the resources that you use supports the determination of a fair cost apportionment. Furthermore, as I will explain in the next section because system planning considers peak demand in all months as well as year-round hourly load data, the 12 CP method is also fair in that it reflects cost causation. The 12 CP method also produces consistency across jurisdictions because it is used in North Dakota, South Dakota, and Minnesota. Absent a compelling reason, it would be contrary to the Commission's policy to change to a different allocator. The 12 CP method is also simple to administer.

III. FAIR COST APPORTIONMENT

Q. WHAT TOPICS DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony I show that the 12 CP demand allocator does result in the fair apportionment of production and transmission costs. I've structured this section around the following three principles:

1. 12 CP is reflective of how customers use the system.
2. 12 CP is reflective of how production resources are planned and is reflective of cost causation.
3. 12 CP is reflective of how MISO charges utilities for regional transmission services.

A. 12 CP is Reflective of How Customers Use Existing Production and Transmission Resources

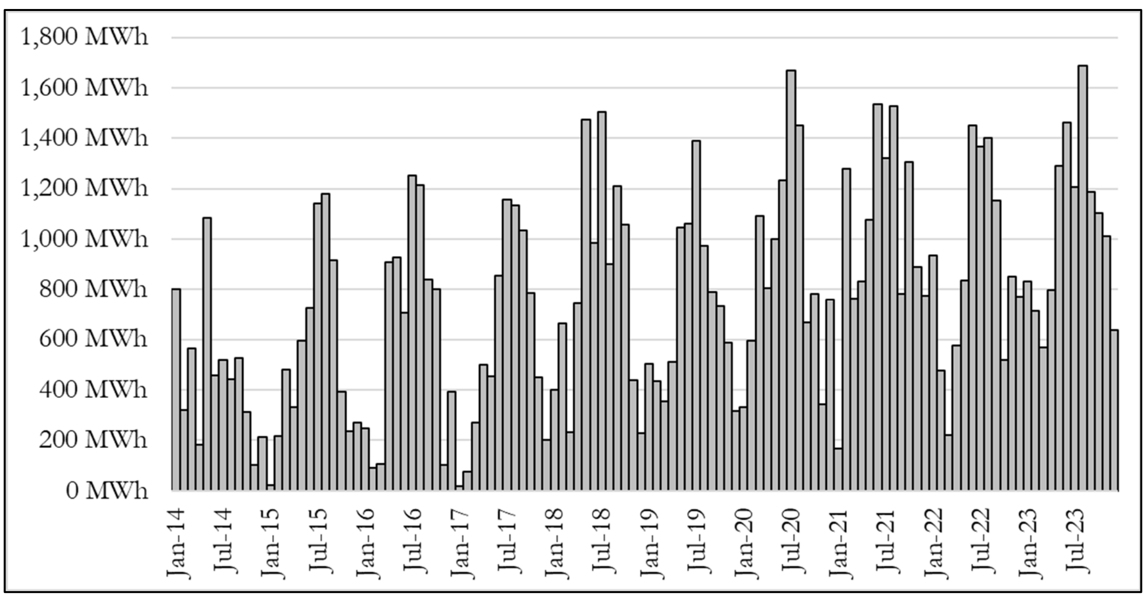
Q. WHY IS IT IMPORTANT TO CONSIDER HOW CUSTOMERS USE PRODUCTION AND TRANSMISSION RESOURCES WHEN ASSESSING THE FAIR APPORTIONMENT OF COSTS?

A. Many utility rate practitioners put heavy weight on the consideration of cost causation. Meaning, they focus on loads that may drive the addition of new production and transmission resources in the future. But when assessing the fairness of cost apportionment, I believe it is also appropriate to consider how customers use existing resources. Although the NSP System's peak demand occurs during the summer months, its resources are in use throughout the year. The 12 CP demand allocator reflects customer use in each month and is therefore more reflective of overall usage of resources.

Q. ARE ALL OF THE COMPANY'S PRODUCTION RESOURCES USED THROUGHOUT THE YEAR?

A. Yes. The Company provided me with hourly dispatch of their production resources for the 10-year period 2014 to 2023. The data reveals that baseload, intermediate, and peaking resources have been utilized in each month over the 10-year period. For peaking units there were months in 2015 and 2017 where the dispatch was minimal, however, it was not zero. The graph of monthly maximum dispatch of peaking units is particularly revealing. It demonstrates that peaking units are being called upon more frequently than in the past in the winter and shoulder months.

Figure 2
Maximum Hourly Peaker Dispatch 2014-2023



Q. WHY IS IT SIGNIFICANT THAT PEAKING RESOURCES ARE BEING DISPATCHED MORE FREQUENTLY THAN IN THE PAST IN THE WINTER AND SHOULDER MONTHS?

A. Peaking units are typically the last generating units to be dispatched due to higher cost and lower efficiency compared to other thermal generation. Their use during these "off peak" months indicates that system conditions associated with high customer demand or other conditions have put a reliability strain on the grid. Peaking units are needed year-round for purposes beyond providing peak shaving (i.e., being the last unit dispatched to meet a singular system peak). They are needed to serve load during the spring and fall seasons (maintenance season) when larger generators are offline for regular maintenance and repairs, and they are used for short-term generation to fill demand needs when renewable generation is low. They are also needed for winter heating load when non-dispatchable and renewable generation are unavailable. Peaking generators, therefore, operate year-round, indicating that customer load in each month of the year impacts the costs of operating the system reliably.

Q. COMPARED TO OTHER ALTERNATIVES, IS THE 12 CP DEMAND ALLOCATOR MORE REFLECTIVE OF HOW CUSTOMERS USE GENERATION AND TRANSMISSION ASSETS?

A. Yes. Alternative demand allocators such as the 1 CP or 4 CP reflect a narrower assessment of how customers use the NSP System. Focusing on a single or four peak demand hours will not reflect the seasonal variation in customer use or the month-to-month needs of the system that I discussed above. Put differently, these methods do not reflect how peaking units are used in each of the 12 months of the year. Selecting a broader demand allocator will better reflect changing usage patterns and result in a fairer apportionment of costs.

B. 12 CP is Reflective of How New Production Resources are Planned

Q. PLEASE DESCRIBE THE PROCESS BY WHICH NEW PRODUCTION RESOURCES ARE SELECTED.

A. At a high level, utilities typically go through a two-step process to determine if new resources are needed, and, if so, what type of resource is most appropriate. First, the company compares the production resources it currently controls to the expected peak demand from its customers to assess if new generation is needed. Second, various resource alternatives are evaluated to see which would fit the overall load patterns of customers the best and result in the overall lowest system costs.

Q. WHICH PEAK DEMANDS ARE CONSIDERED WHEN PLANNING FOR NEW PRODUCTION RESOURCES?

A. Utility resource planners now use models that forecast loads for every hour in a year (8,760 hours). Planning for new resources within utilities is not limited to considering just annual peaks or even just seasonal peaks. For its part, recognizing that resource adequacy concerns are not just limited to the summer season, the Midcontinent Independent System Operator (MISO) recently adopted a seasonal construct that looks at peak demand and production resources in every month to ensure reliability.[4] MISO conducts a Planning Resource Auction where market participants buy and sell production capacity such that each load serving entity has sufficient capacity to cover their peak demand plus a reserve margin in each of the four seasons:

- Summer: June through August
- Fall: September through November

[4] MISO Resource Adequacy Business Practice Manual BPM-011-r28 page 19.

- Winter: December through February
- Spring: March through May

The Company must ensure that it has sufficient resources in each season to meet the MISO reliability criteria.

Q. ONCE THE AMOUNT OF PRODUCTION CAPACITY REQUIRED IS DETERMINED, HOW DOES A UTILITY SELECT THE TYPE OF GENERATION TO BUILD OR PURCHASE?

A. The selection of which type of generation to select is based on the fixed cost to build or purchase the unit and then the on-going variable operating cost of the unit to generate power. Typically, power plants with lower variable cost for generation have higher fixed construction costs, and vice versa. So, a utility will have to assess the value of lower generation costs by simulating hourly customer load and the generation of other existing units. If hourly customer load is regularly in excess of what existing generation can economically supply, then a utility may select an intermediate or baseload type unit despite their higher upfront fixed costs.

Q. HAS THE TRANSITION TO MORE RENEWABLE ENERGY CHANGED THE WAY IN WHICH A UTILITY SELECTS THE TYPE OF GENERATION NEEDED?

A. A utility may choose to deploy additional renewable generation based on low-cost energy and environmental goals. However, they still must ensure the year-round reliability of the system and must balance the tradeoff between fixed and variable costs. In this new energy transition paradigm, it is unlikely that new baseload resources will be the least costs solution. Rather, inexpensive renewable energy paired with low cost peakers are likely to predominate resource selection. However, year-round customer load may drive the decision to extend the life of existing carbon free baseload resources.

Q. WHEN DID MISO ADOPT THE NEW SEASONAL CONSTRUCT FOR GENERATION PLANNING AND RELIABILITY?

A. The Federal Energy Regulatory Commission (FERC) approved MISO's shift from its summer focused resource adequacy construct to a new four-season construct in August of 2022, with specific planning reserve margins for each season. The new process better reflects the risks that the region now faces in winter and shoulder seasons due to fleet change, more frequent and severe extreme weather, electrification, and other factors. This new construct seeks to ensure that resources will be available when they are needed most by aligning resource accreditation with availability during the highest risk periods in each season.

Q. DID THE CHANGE HAVE ANY CONNECTION TO THE INCREASING PREVALENCE OF RENEWABLE GENERATION RESOURCES?

A. Yes. MISO's change to a seasonal planning construct was partially a response to the higher penetration of variable renewable resources. There was a recognition that planning must go beyond the evaluation of customer peak demand and investigate the implications of renewable generation that was below the forecasted level.

Q. YOU REFERRED EARLIER TO PLANNING RESERVE MARGINS, PLEASE EXPLAIN.

A. Planning reserve margin (PRM) is incremental capacity MISO adds to the forecasted peak load in order to ensure that customers can be served reliably even in the event of higher than expected load or a forced outage at a power plant. PRMs are typically set by conducting a loss of load expectation (LOLE) analysis. A LOLE analysis evaluates the likelihood of having insufficient generation resources to meet customer needs. The analysis will go hour-by-hour and assess the probability of higher than expected load and the probability that power plants will be offline based on their historic reliability.

Q. WHAT ARE THE CURRENT SEASONAL PRMS FOR THE COMPANY'S MISO RELIABILITY ZONE?

A. MISO published the current PRMs in spring of 2024. For Local Resource Zone 1 (LRZ1), in which the Company operates, MISO set the following PRMs:

- Summer 2024 9.0 percent
- Fall 2024 14.2 percent
- Winter 2024-25 27.4 percent
- Spring 2025 26.7 percent

Q. WHY ARE THE PRMS HIGHER IN THE WINTER AND SPRING SEASONS?

A. Forecasted peak demand has increased since 2023-2024 season, with increased peak demand forecasted in the winter for MISO north. Also, non-summer PRMs tend to be higher due to higher forced outage rates in these seasons, planned maintenance (as described above) and increased frequency of extreme weather events.

Q. WHAT IS THE IMPLICATION OF HAVING HIGHER PRMS IN THE FALL, WINTER, AND SPRING SEASONS?

A. The higher PRMs in the fall, winter, and spring seasons imply that incremental load additions in those months result in larger resource capacity requirements.

It also means that the difference between summer and winter months is much smaller when PRMs are included in the calculations. Looking at only monthly peak demands (without PRMs included), the average of the summer peaks is approximately 40 percent higher than the average of the winter peaks. However, when the PRM gross up is applied to the seasonal peaks, the actual total capacity requirement in the summer is only 20 percent higher than the winter requirement.

Table 1
Monthly Peak Demand & Capacity Requirements

	2023 WN Peak Demand	MISO LRZ1 Seasonal Planning Reserve Margin	Capacity Requirement
Jan-23	4,775 MW	27.40%	6,083 MW
Feb-23	4,711 MW	27.40%	6,002 MW
Mar-23	4,312 MW	26.70%	5,464 MW
Apr-23	4,919 MW	26.70%	6,233 MW
May-23	5,580 MW	26.70%	7,070 MW
Jun-23	6,504 MW	9.00%	7,090 MW
Jul-23	6,867 MW	9.00%	7,484 MW
Aug-23	6,583 MW	9.00%	7,175 MW
Sep-23	6,252 MW	14.20%	7,140 MW
Oct-23	4,683 MW	14.20%	5,348 MW
Nov-23	4,457 MW	14.20%	5,090 MW
Dec-23	4,724 MW	27.40%	6,019 MW
Summer Average	6,651 MW		7,250 MW
Winter Average	4,737 MW		6,034 MW
Summer - Winter	1,915 MW		1,215 MW
Summer ÷ Winter	**140.42%**		**120.14%**

Q. ARE THERE OTHER SEASONAL-RELATED FACTORS TO WHICH YOU WOULD LIKE TO DRAW ATTENTION?

A. Some states have enacted or are considering policies to support the electrification of heating. To the extent that the adoption of electric heat pumps grows in the future winter peak demands can be expected to grow faster than summer peak demands. This narrowing between seasonal demands further supports the use of year-round load data, like that used in the 12 CP allocator, for cost allocation.

Q. GIVEN MISO'S MOVE TO A SEASONAL PLANNING CONSTRUCT, WOULD A DEMAND ALLOCATOR BASED ON THE COINCIDENT PEAKS IN THE FOUR SEASONS (SEASONAL 4 CP) BE AN APPROPRIATE DEMAND ALLOCATOR?

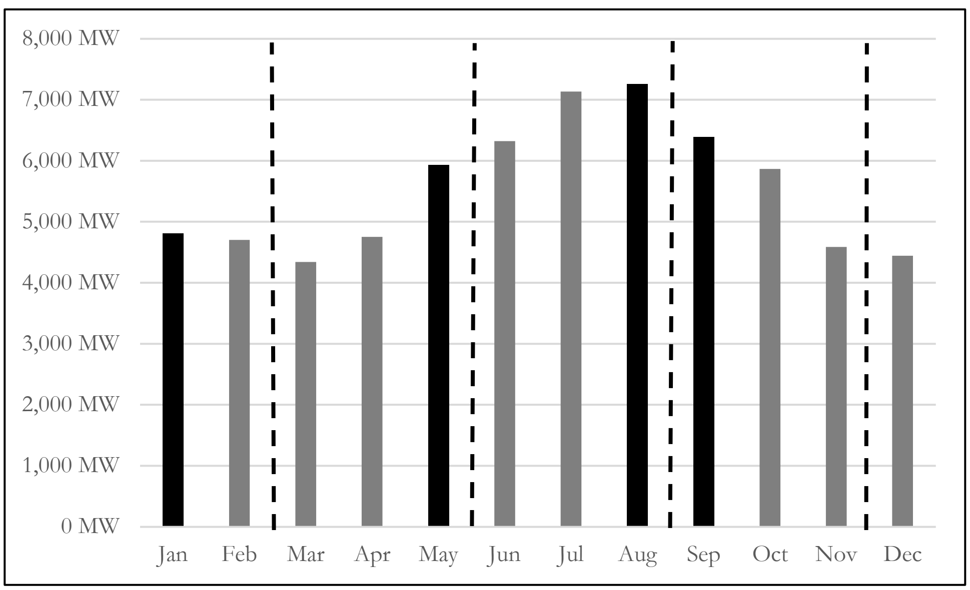
A. No. Performing jurisdictional cost allocation based on a Seasonal 4 CP would be quite unusual. The methodology is not discussed in the NARUC Cost Allocation Manual, and I have not seen it used in any of the jurisdictions that I have researched. Furthermore, MISO's shift to a seasonal planning construct implies that system planning has moved closer to 12 CP demand allocation than has been the case historically.

Q. WOULD SEASONAL 4 CP BE AS REFLECTIVE OF YEAR-ROUND LOAD AS THE 12 CP DEMAND ALLOCATOR?

A. No. One of the advantages of the 12 CP approach is that it specifically uses peak demand information from each month. A Seasonal 4 CP would have the unexpected result of focusing demand allocation on the extended summer season of May through September because the peak spring and fall months would be those closest to summer.

To demonstrate this, I ran an analysis of actual seasonal peak demands from 2013 through 2023 and in each year of the spring (March, April, May) peak demand occurred in May and in each year of the fall (September, October, November) peak demand occurred in September. Given the NSP System's unique characteristics, the use of a Seasonal 4 CP methodology would essentially result in a de facto summer allocator with one winter month added in. In light of this, Seasonal 4 CP will not provide results that would more equitably apportion system costs than 12 CP. The following figure illustrates the actual peak demands for 2023 and highlights the months that would be included the Seasonal 4 CP.

Figure 3
Actual Monthly Peak Demands 2023

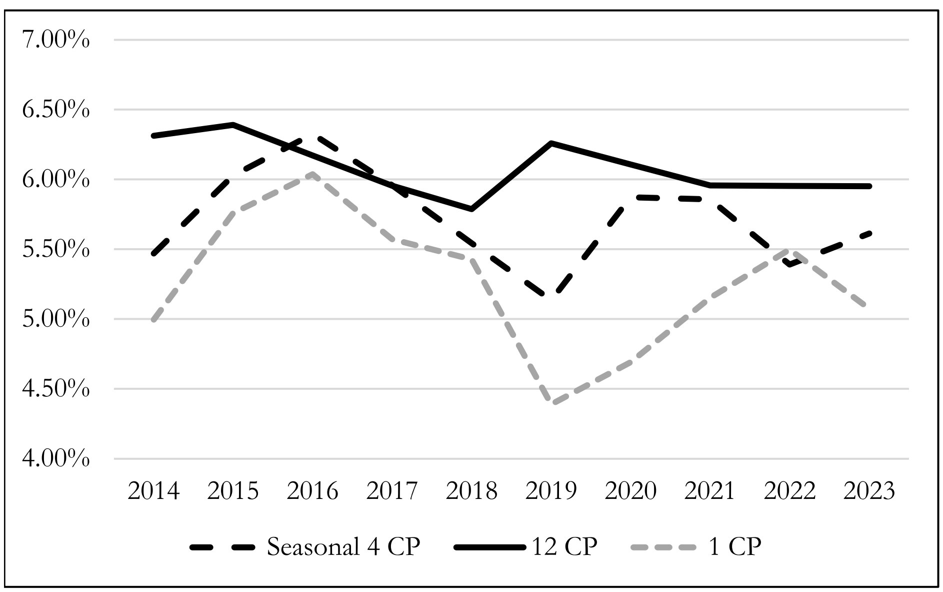


Q. WHAT CONCLUSIONS DO YOU DRAW FROM THIS ANALYSIS?

A. I believe that 12 CP is the best allocation method for the Company to use. The 1 CP allocation methodology is the most restrictive approach that could be used. The focus on a singular peak ignores the reality that system reliability is critical in each month of the year and that variable generation and resource outages can drive the need for incremental generation. Although I believe Seasonal 4 CP is superior to 1 CP, it is still not as appropriate as 12 CP.

Furthermore, the 1 CP methodology is the most unstable allocation. The results of the 2015 Study showed that the 1 CP approach was the least stable out of the 12 alternatives evaluated. I have recreated a similar analysis in the figure below. It demonstrates how the 1 CP approach is much more variable than either the Seasonal 4 CP or the 12 CP. The figure also shows that the results of the Seasonal 4 CP are much closer to the 12 CP demand allocation than are the results for the 1 CP.

Figure 4
1 CP vs Seasonal 4 CP vs 12 CP: 2013-2023



Q. WILL A CONTINUED TRANSITION TO A LARGER PROPORTION OF RENEWABLES MAKE THE 12 CP DEMAND ALLOCATOR LESS SUITABLE?

A. No. If anything, the higher penetration of renewables drives the need to consider year-round load more carefully. Before the transition, summer peak loads were a more prominent consideration. But with a large number of renewable resources, planners must consider peak demand and the impact of variable, non-dispatchable generation. It is possible that in the fall, winter, and spring months, when customer demand is not as high as it is in the summer season, additional dispatchable resources will be needed for reliability during periods when renewables are not generating. This year-round reliability assessment makes 12 CP even more reflective of how generation resources are planned.

Q. OVERALL, DOES PRODUCTION PLANNING SUPPORT THE USE OF 12 CP DEMAND ALLOCATOR?

A. Yes. When planning for production resources the Company must consider peak demand from all 12 months. Furthermore, MISO has set higher PRMs for the fall, winter, and spring which narrows the gap between those seasons and the summer peak. Finally, when selecting the optimal type of new production resource to construct, the Company will assess load in all 8,760 hours of the year, and 12 CP is more reflective of that portion of the planning. This is true of both the traditional approach to selecting between baseload, intermediate, and peaking resources and for resource selection as the NSP System moves to higher penetrations of renewable energy.

The use of a 1 CP or a Seasonal 4 CP demand allocator would place too much emphasis on a smaller number of peaks focused on the summer season.

Particularly with the growth of renewable generation, it is increasingly important to evaluate system load in all months.

Q. WHAT DO YOU CONCLUDE WITH REGARD TO FAIR COST APPORTIONMENT?

A. The 12 CP demand allocator results in the fair apportionment of costs for several reasons. First, the use of 12 coincident peaks is a fair reflection of how customers use the Company's resources. I demonstrated that even peaking resources are being utilized in every month of the year and from a fairness perspective I believe that it is reasonable to allocate the cost of resources based on customer year-round usage.

Second, MISO's new seasonal planning construct evaluates resource needs in each season of the year. This shift away from focusing just on summer peak demand further supports the use of the 12 CP demand allocator as being reflective of generation cost causation.

Finally, the type of generation selected is dependent on year-round load patterns. Higher load levels outside the summer peak may drive the selection resource that are more expensive to construct. So the use of a year-round 12 CP demand allocator also captures the cost causation associated with the type of generators selected. This is even more true as the level of variable renewable generation increases.

C. 12 CP is Reflective of How MISO Charges Utilities for Regional Transmission Services

Q. IS THE COMPANY CHARGED FOR TRANSMISSION RESOURCES BY MISO?

A. Yes. As a generator and a load-serving entity, the Company is charged by MISO for transmission services used to generate power and serve its load. MISO provides a variety of transmission services under its tariffs including Point to Point Firm (Schedule 7), Point to Point Non-firm (Schedule 8), and Network Integration Transmission Service (Schedule 9).[5]

Q. HOW DOES MISO ASSIGN TRANSMISSION COSTS?

A. MISO has split its footprint into Cost Allocation Zones, which are used to allocate costs of transmission under the tariff schedules above. These zones are further broken down into transmission pricing zones, which are then used to calculate transmission rates for a specific customer. Zonal rates are calculated using a 12 CP method to allocate and charge costs to each utility.

Q. WHY IS 12 CP AN APPROPRIATE METHOD FOR MISO TO USE IN ALLOCATING TRANSMISSION COSTS?

A. Using a 12 CP allocator accurately reflects the way MISO's system performs through the entirety of the year, not based on a single summer peak event. MISO is assigning costs based on the seasonal variability inherent in operating a large electric system. By separating this further into Zonal rates, they also account for geographic diversity within their large footprint.

Q. WOULD USING A 1 CP OR A 4 CP DEMAND ALLOCATOR IN NORTH DAKOTA CREATE A MISMATCH BETWEEN HOW TRANSMISSION COSTS ARE INCURRED AND HOW THEY ARE ALLOCATED ACROSS STATES?

[5] https://www.misoenergy.org/legal/rules-manuals-and-agreements/tariff/

A. Yes. Since MISO transmission costs are specifically charged using 12 CP, if transmission costs are allocated across states using a different demand allocator there will be a disconnect between the customer loads and allocated costs. This would likely result in states paying more or less of their fair share of MISO transmission costs. Specifically, if a 1 CP demand allocator was used for transmission costs North Dakota customers would pay less for transmission than the costs their load creates for the Company.

IV. CONSISTENCY AMONG JURISDICTIONS

Q. HOW ARE GENERATION AND TRANSMISSION COSTS CURRENTLY ALLOCATED ACROSS THE COMPANY'S THREE JURISDICTIONS?

A. Currently, the 12 CP demand allocator is used in North Dakota, South Dakota, and Minnesota. Most recently the South Dakota Commission approved the rates based on a 12 CP demand allocation in Docket No. EL22-017 and the Minnesota Commission approved rates based on a 12 CP demand allocation in Docket No. E002/GR-21-630.

Q. WHY IS CONSISTENCY ACROSS JURISDICTIONS AN IMPORTANT CONSIDERATION?

A. Unless a consistent allocator is used across all jurisdictions, there is a risk that the Company will under- or over-collect total costs. Commissions in different states often make different determinations regarding appropriate annual expenditures, prudent capital investments, and the correct financing costs. This is an appropriate part of regulation and reflects differences in judgement. However, if Commissions select different allocation methodologies a utility may be denied the opportunity to recover the approved revenue requirements. This becomes a de facto disallowance that is not based on a determination of prudence. Unfounded disallowances are contrary to the goals and intents of modern utility regulation. By approving an allocator consistent with those used in the Company's other jurisdictions, the Commission will help ensure that the Company has a reasonable opportunity to earn its approved revenue requirement.

Q. IS 12 CP A COMMON DEMAND ALLOCATOR?

A. The 2015 Study included the following figure. It shows that the 12 CP allocator was the most commonly used allocation method in the region. To my knowledge, these allocation methods are still being used.

Figure 5
Jurisdictional Allocation Methods in the Upper Midwest

	N. Dakota	S. Dakota	Minnesota	Montana	Iowa	Wisconsin	Michigan
Xcel Energy	12CP	12CP	12CP	--	--	12CP	12CP
Montana-Dakota	12CP	12CP	--	12CP	--	--	--
Ottertail Power	EqPk/1CP	EqPk/1CP	EqPk/1CP	--	--	--	--
Black Hills Power	--	12CP	--	12CP	--	--	--
Interstate Power	--	--	12CP	--	12CP	--	--
MidAmerican	--	A&E	--	--	A&E	--	--
Minnesota Power	--	--	100% MN system	--	--	--	--
Northwestern	--	100% SD system	--	100% MT system	--	--	--

Q. WHAT DO YOU CONCLUDE REGARDING CONSISTENCY OF ALLOCATION METHODOLOGIES ACROSS JURISDICTIONS?

A. It is understandable that different Commissions have varying opinions regarding what allocation methodology to choose given the lack of a single established method for definitively selecting among them. I recommend that the North Dakota Commission choose the method that maintains consistency across the Company's jurisdictions, which is 12 CP.

V. ADMINISTRATIVE EASE

Q. IS THE 12 CP DEMAND ALLOCATOR EASY TO ADMINISTER?

A. Yes. While I am not able to quantify the ease of administration, the 12 CP method is a simple sum or average of peak demands across the 12 months. Peak averaging demand allocators, like 12 CP, are the simplest methods that are used.

Q. ARE THERE MORE COMPLICATED DEMAND ALLOCATORS?

A. Yes. Some allocators apply weighting factors to each of the peak demands included in the calculations. This adds a bit of complexity to the calculations and opens the possibility of disagreement on how the weighting factors should be selected. Then there are methods that first divide or stratify costs into categories and then apply different allocation methods to each category. For these methods the process of stratifying costs can be more complex and data intensive. Finally, I also have experience working with the Probability of Dispatch (POD) method for allocating generation costs. The POD approach relies upon hourly dispatch simulation and correlation of generation to hourly customer load. Dispatch simulations are inherently complex and require hundreds of input assumptions and proprietary software.

Q. WHAT IS YOUR OVERALL CONCLUSION REGARDING THE EASE OF ADMINISTRATION OF THE 12 CP DEMAND ALLOCATOR?

A. The 12 CP method is simple to administer, but so are some other methods. Of all the factors that one might consider when selecting an allocation method, the ease of administration of the 12 CP demand allocator should be of the lowest concern.

VI. THE 2015 DEMAND ALLOCATION STUDY

Q. WHAT WAS THE PURPOSE OF THE 2015 DEMAND ALLOCATION STUDY?

A. As I previously discussed, the February 2014 Amended Settlement Agreement in the 2012 Rate Case included a provision that required a third-party study of jurisdictional demand allocators. The resulting 2015 Study was to analyze a number of methodologies and propose a recommendation on the one or more methodologies that reasonably represents cost causation on the Company production and transmission costs.

Q. WHAT DIRECTION DID THE COMMISSION GIVE WITH RESPECT TO THE 2015 STUDY?

A. In its February 26, 2014 Order Accepting Settlement in Case No. PU-12-813, the Commission directed that the following factors be considered:

1. Representative of Costs – How well does the method reflect the load profiles of the Xcel Energy's three jurisdictions, the likely drivers for planning and operating the integrated system, and the likely reasons the utility incurred the costs?
2. Stability – Does the method produce cost allocation factors that do not overly fluctuate from year to year?
3. Simplicity – Is the allocation method understandable and simple to administrate?

4. Predictability – How well can the method's actual allocation of costs for a given year be forecasted ahead of time using either historical trends and/or projected data?
5. System Cost Recoverability – Will the allocation method provide an opportunity for Xcel Energy to recover 100 percent of its approved system costs in conjunction with the method approved in the Xcel Energy's other state jurisdictions?

These five factors overlap somewhat with three Commission-approved criteria that I discussed above. I will discuss each of the five, with a particular focus on the conclusions reached in the 2015 Study and the continued validity of those conclusions. This involved re-creating some of the same analyses used in the 2015 Study, but with updated data.

Q. WHAT CONCLUSIONS DID THE 2015 STUDY DRAW?

A. The 2015 Study evaluated 12 alternative allocation methods using data from 2004 to 2013. The authors concluded that:

> Based on our analysis of 10 years of data described in our report, we identified that there are differences in the load characteristics of the three jurisdictions of the NSPM system. Because of these differences, allocators which use both demand and energy or which use several demand values (and hence proxy the impacts of demand and energy) appear to be appropriate, based on cost-causation criteria. Historically, all three jurisdictions have used a "12CP allocator" which allocates costs in proportion to the share of monthly peak demand averaged across all twelve months of the year. The individual state territories have some dissimilarity in their load profiles, but it appears that their adoption of the 12CP method historically has been reasonable.

Q. IS THE 12 CP DEMAND ALLOCATOR MORE OR LESS REPRESENTATIVE OF COST CAUSATION THAN IT WAS DURING THE 2015 STUDY?

A. First, as I previously discussed, MISO has adopted a seasonal reliability construct since the 2015 Study was conducted. For that reason, the 12 CP demand allocator is certainly more reflective of cost causation because it captures year-round load like the MISO process now does. Second, I investigated the Company's historic peak loads to see if summer peaks have become more pronounced since the 2015 Study was completed. To conduct this analysis, I compared the average of the three summer coincident peaks (June, July, Aug) to the three winter peaks (Dec, Jan, Feb) for the 10 years included in the 2015 Study (2004-2013) and for the most recent ten years (2014-2023). The results of the analysis show that the ratio of summer to winter peak demands is substantially the same over the past ten years as it was over 2004-2013, and so this analysis suggests 12 CP is as representative as it was during the period considered for the 2015 Study.

Table 2
Comparison of Summer and Winter Peak Loads

	Average 3CP Summer	Average 3CP Winter	3CP Summer ÷ 3CP Winter
2004-2013	6,977	5,265	1.33
2014-2023	6,861	4,995	1.37

Looking at the year-by-year results reveals that the ratio between summer and winter loads has varied between 1.21 and 1.48, with no obvious trend in either direction, which again suggests 12 CP remains approximately as representative as during the 2004 to 2013 period.

Figure 6
3CP Summer & 3CP Winter

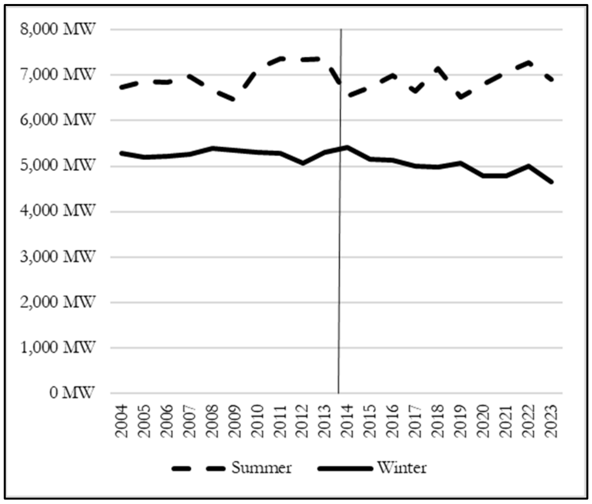
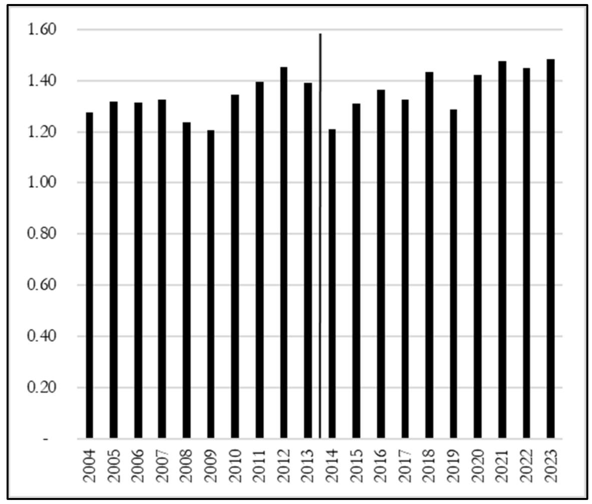


Figure 7
3CP Summer ÷ 3CP Winter



Q. HAVE YOU CONDUCTED ANY OTHER ANALYSIS TO DETERMINE IF THE COMPANY'S PEAK DEMANDS HAVE CHANGED MATERIALLY SINCE THE 2015 STUDY?

A. Yes. I conducted a similar study comparing the actual annual peak demand (1 CP) to the actual average of the year-round monthly peak demands (12 CP). The results again showed that the ratio between the 1 CP and the 12 CP has not materially changed since 2004 to 2013 and that there is no discernible trend in the ratio between the two peak demand measures. Like the analyses discussed immediately above, this suggests 12 CP remains about as representative as during the period studied for the 2015 Study.

Table 3
Comparison of 1 CP and 12 CP

	Average 1CP	Average 12 CP	1CP ÷ 12CP Winter
2004-2013	7,286	5,677	1.28
2014-2023	7,242	5,469	1.32

Figure 8
Actual 1CP & 12CP

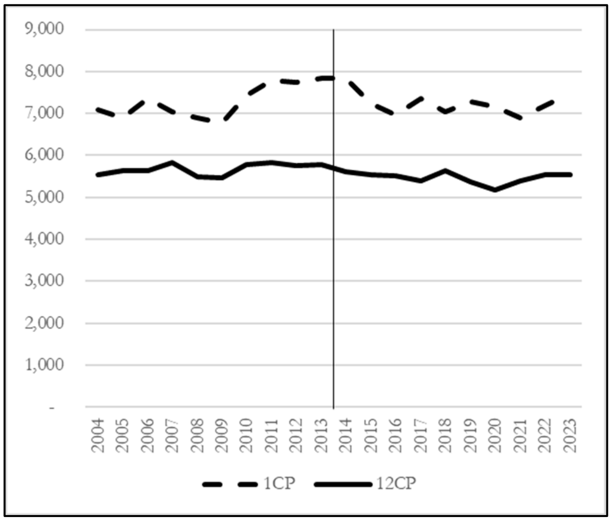
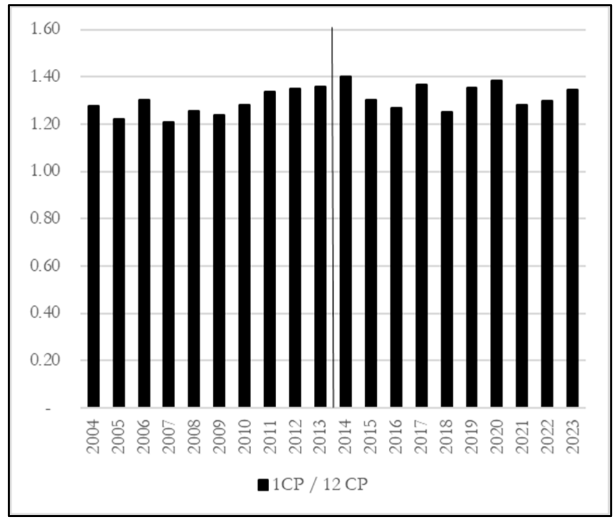


Figure 9
Actual 1CP ÷ 12CP



Q. WHAT DO YOU CONCLUDE REGARDING YOUR ANALYSES COMPARING PEAK DEMANDS OVER TIME?

A. The preceding analyses demonstrate that the relationship between summer peak demands and winter and year-round peak demands has not changed. Because summer peak demands have not become more pronounced on the NSP System and because the 12 CP demand allocator was deemed to be representative of costs in 2016, the 12 CP remains representative of cost in 2024.

Q. IS THE 12 CP A STABLE DEMAND ALLOCATION METHODOLOGY?

A. Yes. The 2015 Study included a measure of stability by first fitting a linear trend line to the annual North Dakota allocation factors for the various methodologies under consideration. The 2015 Study then measured stability by calculating the root mean squared error (RMSE), which essentially quantifies how much the actual allocation factors deviated from the predicted value. The 2015 Study demonstrated that 12 CP was among the most stable methodologies evaluated.

Q. HAVE YOU CONDUCTED A SIMILAR STUDY REGARDING THE STABILITY OF DEMAND ALLOCATORS?

A. Yes. Using peak demand data from 2004 through 2023 I've replicated the analysis performed in the 2015 Study. I calculated the RMSE of the North Dakota demand allocator for both the 1 CP and the 12 CP methods. The results showed that the 12 CP was considerably more stable than the 1 CP methodology. The 12 CP had a RMSE of 0.18 percent while the 1 CP had a RMSE of 0.53 percent. The following figures provide an illustration of how much more variable the 1 CP demand allocation factor is and, in contrast, how 12 CP is a more stable allocator.

Figure 10
RMSE 12 CP

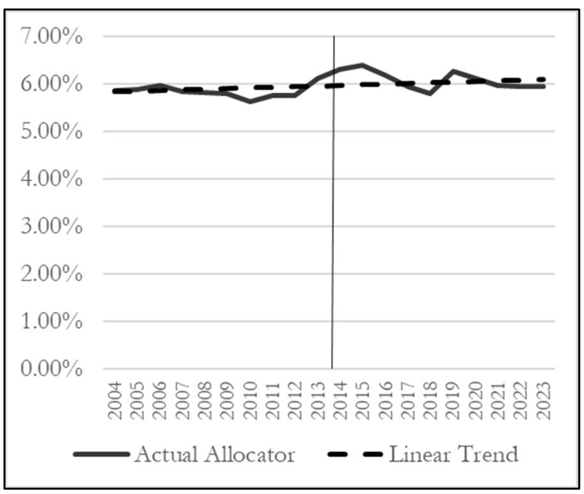
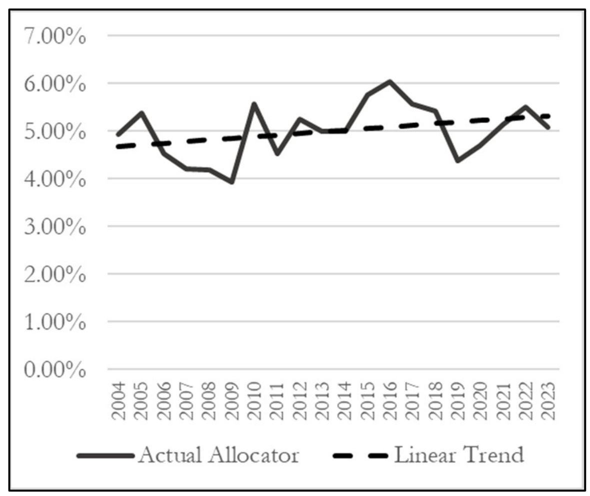


Figure 11
RMSE 1 CP



Q. IS THE 12 CP DEMAND ALLOCATOR PREDICTABLE?

A. Yes. To test the predictability of demand allocators the 2015 Study compared the Company's budgeted North Dakota demand allocator to the actual allocator. To measure the overall predictability the 2015 Study reported the average of the absolute differences between the budgeted and actual allocators. I have recreated that analysis using data from 2005 through 2023. Like the stability analysis, the evaluation of predictability shows that the 12 CP method was much more consistent and therefore easier to predict in comparison to the 1 CP method. The average absolute difference between the budgeted and actual North Dakota demand allocators was 0.15 percent for the 12 CP and 0.49 percent for the 1 CP. The following figures illustrate that the actual North Dakota demand allocators were much closer to the budgeted value under the 12 CP method.

Figure 12
Budget vs Actual 12 CP

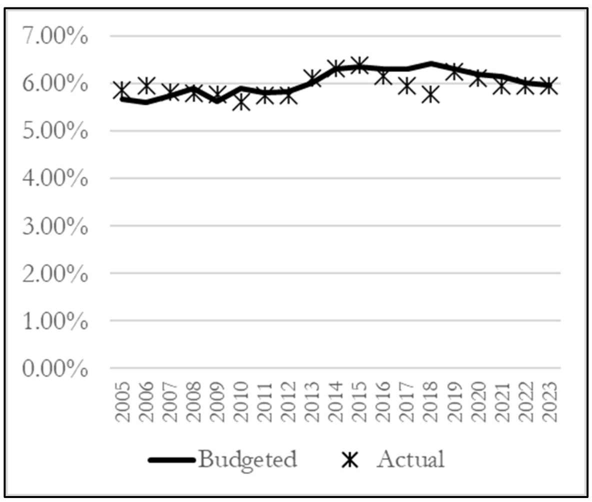
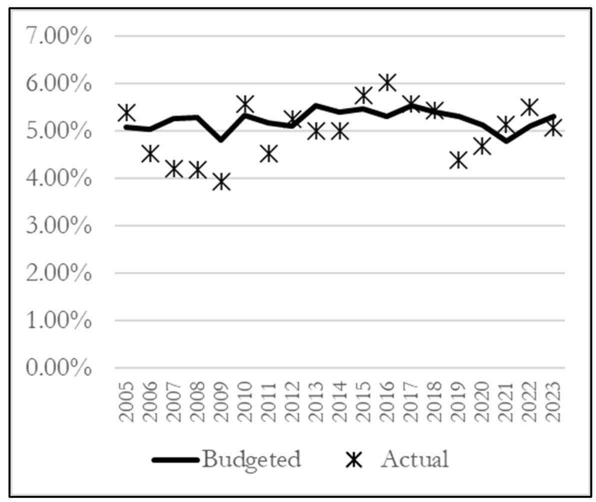


Figure 13
Budget vs Actual 1 CP



Q. IS THE 12 CP DEMAND ALLOCATOR UNDERSTANDABLE AND SIMPLE TO ADMINISTER?

A. Yes. While it is not possible to quantify the simplicity of a demand allocation methodology, the 2015 Study did not conclude that the 12 CP method was complex in any way. I agree with the conclusion reached by the 2015 Study. As I discussed above, the 12 CP method is simple to administer.

Q. DOES THE 12 CP DEMAND ALLOCATOR ENSURE THAT THE COMPANY WILL ACCURATELY RECOVER COMMISSION APPROVED REVENUE REQUIREMENTS?

A. This factor overlaps with the discussion above regarding consistency among jurisdictions. The 12 CP allocator better positions the Company to have a reasonable opportunity of accurately recovering its approved revenue requirements because it avoids the risks of under- or over-collection due to inconsistent allocators.

VII. CONCLUSION

Q. PLEASE BRIEFLY SUMMARIZE YOUR TESTIMONY.

A. I started by discussing the fundamentals of cost allocation and explained that there is not a universally accepted methodology for cost allocation. I then discussed how the 12 CP cost allocation method that is currently used, and that I am recommending, fits with the three criteria from a prior Commission decision. The 12 CP method is fair, is consistent with the methods used in the Company's other jurisdictions and is easy to administer. The 12 CP method is fair because it is reflective of how customers use the electric grid year-round, is reflective of how the system is planned (including under MISO's new seasonal resource construct), and is the methodology that MISO uses to calculate transmission charges. I also determined that allocating costs based on a single yearly peak event, the 1 CP method, is not reflective of how the modern electric grid is utilized by customers, nor does it fairly allocate the costs of the dynamic seasonal and winter peaking.

Finally, I revisited the factors that the Commission laid out for the 2015 Study: (1) Representativeness of Costs, (2) Stability, (3) Simplicity, (4) Predictability, and (5) System Cost Recoverability. Using more recent data, I performed the same analyses as were done for the 2015 Study and determined that the 12 CP allocation methodology remains approximately as representative now as in 2015 using those metrics. I also present updated analysis showing that the 12 CP is more stable and predictable than the 1 CP method. The facts supporting the simplicity of administering the 12 CP method are unchanged since 2015 as are those showing it will result in accurate recovery of Commission approved costs.

Overall, I recommend that the Commission approve the use of the 12 CP demand allocator in this proceeding for fixed costs related to generation and transmission.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

STEVEN W. WISHART
ASSISTANT VICE PRESIDENT

Leading utility economist with 18 years of experience at a large Midwest electric and natural gas utility. Expert witness in over 35 regulatory proceeding covering various economic and financial topics. Innovator in cost allocation and rate design. Additional expertise in performance-based rate making, long-range forecasting and strategy, transportation electrification, economic development, decarbonization, extension policy, and affordability issues.

AREAS OF EXPERTISE

Cost Allocation & Rate Design

- Cost allocation and rate design are the foundational touchpoint between utilities and their customers. Mr. Wishart emphasizes stability in class cost allocation. While cost causation is also a foundational principle, traditional allocation methods can lead to unexpected and unwelcomed cost shifts between customer classes.

  Innovative rate design should drive customers to use the grid more efficiently and lower system costs. Mr. Wishart has successfully implemented default time of use rates for millions of electric customers and created dynamic rate options that reflect real time system conditions.

  Cost allocation and rate design are becoming increasingly important for natural gas utilities. The prospect of heating load electrification requires new approaches. Mr. Wishart works to modernize rate design and cost recovery for natural gas utilities to adapt to the changing policy landscape.

Long Term Planning & Strategy

- Mr. Wishart has nearly a decade of experience in planning new generation resources and implementing decarbonization strategies in the upper Midwest. He worked to develop the Value of Solar (VOS) standard for Minnesota which formed the basis for community solar development in the state. Mr. Wishart also led large RFPs for renewable and dispatchable generation.

  A core tool for utility planning is the ability to perform long term rate and bill analysis. Utilities far too often fail to evaluate the granular impacts that broad strategy decisions will have on customer bills. Mr. Wishart has developed methodologies to comprehensively assess the impacts of a utility's strategic direction and quantify the impact to customers.

PROFESSIONAL HISTORY

Concentric Energy Advisors (2023-Present)
Assistant Vice President

- Supporting client needs with extensive regulatory experience and advanced quantitative analysis.

Xcel Energy, Denver (2014-2023)
Director/Manager, Pricing & Regulatory Analytics

- Provide strategic direction for Public Service of Colorado regulatory strategy and revenue collection
- Serve as Company witness in rate cases and other proceedings
- Manage electric, natural gas, and thermal tariffs
- Manage analysts involved in pricing and rate related analytics

Major Projects:

- 2023 Chair - Edison Electric Institute, Rates & Regulatory Affairs Committee
- 2023 Electric Rate Case – Innovate cost allocation and rate design with leading energy burden analysis.
- 2023 Economic Development – Supported discounted contract to attract 200MW data center to the Denver area which will be Xcel's single largest customer in Colorado.
- 2023 Clean Heat Planning – Developed long range modeling of Xcel Colorado's natural gas business highlighting the rate impacts resulting from aggressive electrification of heating load.
- 2022 DSM Strategic Issues – Sponsored Company's proposal for new DSM incentives including a new a bonus based on carbon reductions and a new mechanism to incent beneficial electrification.
- 2022 Natural Gas Rate Case – Recommended cost allocation and rate design for natural gas system. Also presented recommendation for natural gas revenue decoupling and supported updated to extension policy.
- 2022 Vicechair of Edison Electric Institute Rates and Regulatory Affairs Committee.
- 2022 Adopted testimony for 2022-2025 Renewable Energy Compliance Plan - supporting overall cost impacts of renewable energy.
- 2021 Commercial Electric Vehicle Rates – Two EV rates options based on new analysis of EV load data and system costs impacts.
- 2021 Extreme Weather Event – Testimony in support of recovery of approximately $700 million in incremental fuel expenses associated with Presidents Day weekend weather event.
- 2021 Critical Peak Pricing (CPP) – Testimony in support of dynamic C&I rate option that targets top 40-60 peak hours of the year.
- 2021 Pipeline Safety Integrity Rider – Testimony in support of 3-year extension of integrity rider.
- 2021 Chair of Southern Gas Association Rates and Regulatory Committee.

- 2020 Electric Rate Case – Testimony and strategic leadership for case to update electric rates including development of flat billing and demand charge options for residential customers.
- 2020 Economic Development Rate - Testimony and strategic leadership for case to create discounted C&I rates for qualifying customers locating or expanding operations in Colorado.
- 2020 Transportation Electrification Plan – Testimony regarding rate impacts of electric vehicles and cost recovery of $100 million investment in EV infrastructure and public DCFC.
- 2020 Gas Rate Case - Sponsored revisions to natural gas rates and other tariff updates.
- 2019 Residential Time of Use Rates – Lead proposal to move all Residential customers to mandatory time of use electric dates.
- 2019 Commercial Electric Vehicle Rate – Developed and sponsored new rate for public EV charging stations & fleets.
- 2018 Pipeline System Integrity Adjustment – Witness for three-year extension of $100 million pipeline safety rider.
- 2017 DSM Strategic Issues – Evaluated and sponsored testimony regarding incentives and the financial impacts of energy conservation programs in Colorado.
- 2016 Renewable*Connect – Developed pricing strategies for new customer choice solar product and appeared as Company witness in PUC hearing.
- 2016 Revenue Decoupling Proposal – Strategic development and implementation of Public Service's proposal to sever the link between revenue collection and volumetric sales.
- 2015 Phase II Electric Rate Case – Manage analytic team developing new rates for electric services. Witness testifying on total revenue collection and tariff changes.
- Administration of all PSCo rate riders: Fuel cost adjustment, renewable energy standard adjustment, gas cost adjustment, transmission costs adjustment, purchased capacity cost adjustment, general rate schedule adjustment, DSM adjustment, etc.

Xcel Energy, Minneapolis MN (2012-2014)
Director, Resource Planning & Bidding

- Develop and implement strategic plans for generation resources for Northern States Power operating company.
- Represent the company as an expert witness in regulatory proceedings.
- Oversee RFP processes for new generation resources.
- Develop and implement strategic plans for renewable energy and environmental compliance.
- Manage a team of resource planning analysts.

Major Projects:

- 2013 Wind RFP – Managed an RFP to acquire 750MW of new wind resources in advance of the expiration of the federal PTC. Nominal project value over $1billion.
- Minnesota Value of Solar – Represented the Company as expert witness on the Value of Solar and renewable energy policy.

- 2017-2019 Natural Gas Generation – Represented Xcel Energy as witness regarding economic assessment of new natural gas generation in the NSP region.
- Minnesota Resource Plan – Completed regulatory process for the company's 2013-2025 Resource Plan, with PUC approval in February 2013
- Prairie Island Nuclear Plant Extended Power Uprate (EPU) – Represented Xcel Energy as witness in original EPU application and subsequently developed analysis and regulatory filings to cease work on the uprate project.
- Settlement of North Dakota rate case – Developed strategic plan to separate state energy portfolios, customizing power generation to state level policy goals.
- Prairie Rose Wind – Testified as subject matter expert supporting the economic evaluation of 200MW wind project.

Xcel Energy, Minneapolis/Denver (2009-2012)
Manager, Strategic Planning/Risk Analytics

- Oversee economic evaluation of all large power supply projects for Xcel Energy's three regional operating companies.
- Develop and maintain average rate forecasting models for all Xcel Energy jurisdictions.
- Prepare analysis for senior leadership that reports on expected value and value at risk for new generation assets, power purchases, conservation programs, wholesale sales, and other projects.
- Manage a group of quantitative analysts that evaluate various supply and demand side alternatives.
- Serve as quantitative expert for resource planning and purchased power related dockets.

Major Projects:

- Colorado Clean Air Clean Jobs Act – Retire/repower 900MW of existing coal units in PSCo service territory for compliance with regional NOx legislation.
- 2010 Minnesota Resource Plan – 10 year projection of new resource acquisitions, retirements, renewable energy standard compliance, and enhanced conservation programs.
- 2009 PSCo All-Source Solicitation – Modeling/evaluation of bids totaling 20,000MW in Colorado. Including natural gas, wind, solar PV, solar thermal with storage, compressed air storage, pumped hydro, wind/battery combo, and solar augmented combined cycle.
- Manitoba Hydro CON – Economic valuation of 10yr $1.6B purchase from MH.

Xcel Energy, Minneapolis (2006-2009)
Analyst/Sr. Analyst, Resource Planning

Major Projects:

- 2007 Minnesota Resource Plan
- Witness for nuclear re-licensing application

- Analysis of proposed $2billion IGCC.

Xcel Energy, Minneapolis (2005-2006)
Demand Side Management (DSM) Technical Analyst

- Managed cost/benefit analysis of NSP's $45 million annual conservation and load management activities, including forecasting of financial incentives, and strategic planning.

EDUCATION

University of Minnesota (2002-2005)
PhD (all but dissertation) Applied Economics
Course Work: Emphasis - environmental and natural resource economics. Other course work - Financial economics, econometrics, dynamic programming, production economics, non-parametric frontier analysis, managerial economics, international trade, macro- and microeconomics.

University of Arizona (2000-2002)
MS. Economics
Course Work: Environmental economics, environmental law, econometrics, linear and quadratic programming, production economics, consumer economics.

University of Arizona (1992-1996)
BS Finance

SPONSOR	DATE	DOCKET NO.	SUBJECT
Colorado			
Xcel Energy	May 2023	23AL-0243E	Phase II Electric Rate Case – Class Cost Allocation & Rate Design
Xcel Energy	June 2023	23A-0330E	Economic Development Contract – Marginal Cost of Service & Marginal Revenue
Xcel Energy	March 2023	22AL-0530E	Phase I Electric Rate Case – 15 Year Rate Forecast & Energy Burden Analysis
Xcel Energy	February 2023	22F-0263EG	Customer Complaint – Terms of Interruptible Gas Service
Xcel Energy	September 2022	22AL-0187E	Revenue Decoupling – Application of Rate Impact Cap
Xcel Energy	September 2022	22A-0382ST	Steam Resource Plan – Long Term Strategy for Denver Steam System
Xcel Energy	July 2022	22A-0309EG	DSM Strategic Issues – Incentive Mechanisms for Conservation & Demand Response Programs, Value of Avoided Natural Gas Pipeline Capacity
Xcel Energy	January 2022	22AL-0046EG	Natural Gas Rate Case – Cost Allocation, Rate Design, Revenue Decoupling, Wholesale Contracts, 15 Year Rate Projections, & Extension Policy
Xcel Energy	October 2021	21AL-0494E	Electric Vehicle Rates – New & Revised EV Charging Rates
Xcel Energy	July 2021	21AL-0317E	Phase I Electric Rate Case – Rate Deferral Surcharge, Revenue Decoupling, and Bill Impact Analysis
Xcel Energy	May 2021	21A-0203ST	Storm Uri Cost Recovery for Denver Steam System
Xcel Energy	May 2021	21A-0192EG	Storm Uri Cost Recovery for Electric & Natural Gas
Xcel Energy	February 2021	21A-0071G	Natural Gas Rate Case – Pipeline Safety Rate Adjustment & 15 Year Rate Forecast
Xcel Energy	February 2021	21AL-0091E	C&I Critical Peak Pricing Optional Rate
Xcel Energy	October 2020	20AL-0432E	Phase II Electric Rate Case – Rate Design, Time of Use Rates, & Flat Bill Pricing Option
Xcel Energy	August 2020	20A-0345E	Standardized Economic Development Rate Tariff

SPONSOR	DATE	DOCKET NO.	SUBJECT
Xcel Energy	May 2020	20A-0204E	Transportation Electrification Plan – Electric Vehicle Services Tariff, Xcel Owned DCFC Charging Stations, & Statutory Rate Impact Analysis
Xcel Energy	February 2020	20AL-0049G	Natural Gas Rate Case – Class Cost Allocation, Rate Design, & Bill Impacts
Xcel Energy	December 2019	19AL-0687E	Residential Default Time of Use Rates
Xcel Energy	May 2019	19AL-0309G	Natural Gas Rate Case – Class Cost Allocation, Rate Design, & Bill Impacts
Xcel Energy	May 2019	19AL-0290E	New Electric Vehicle Rate with Critical Peak Pricing
Xcel Energy	January 2019	19AL-0063ST	Steam Rate Case – Sales Volume & Coincident Peak Analysis, Weather Normalization, Rate Design
Xcel Energy	April 2018	18A-0422G & 18A-0247G	Pipeline System Integrity Capital Rider
Xcel Energy	July 2017	17A-0462EG	DSM Strategic Issues – Incentive Mechanisms and Disincentive Offsets
Xcel Energy	July 2016	16A-0546E	Electric Revenue Decoupling – Tariff & Impact Analysis
Xcel Energy	January 2016	16A-0055E	Renewable Connect Customer Choice Program – Tariff Charges & Credits
Xcel Energy	January 2016	16A-0048E	Phase II Electric Rate Case – Rate Design & Tariff Changes
Xcel Energy	March 2015	15AL-0135G	Natural Gas Rate Case – Pipeline System Integrity Cost Recovery, Discounted Contacts, & Bill Impacts
Xcel Energy	May 2014	14A-0491G	Gas Price Volatility Mitigation Plan
Minnesota			
Xcel Energy	July 2013	E002/M-13-603	750MW Upper Midwest Wind RFP
Xcel Energy	November 2012	E002/M-12-1240	Competitive Resource Acquisition Process for Peaking Generation

SPONSOR	DATE	DOCKET NO.	SUBJECT
Xcel Energy	March 2012	IP-6843/WS-10-425	Certificate of Need – Prairie Rose Wind Farm
Xcel Energy	March 2012	E002/RP-10-825	Norther States Power 2011-2025 Electric Resource Plan
Xcel Energy	April 2009	E002/CN-08-509 & E002/CN-08-510	Prairie Island Nuclear Facility – Life Extension & Power Uprate
Xcel Energy	August 2008	E002/CN-08-185	Monticello Nuclear Facility – Power Uprate
North Dakota			
Xcel Energy	April 2013	PU-12-813	Electric Rate Case – Resource Planning & Cost Causation
Xcel Energy	October 2012	PU-12-059	Advanced Prudence Geronimo Wind
Wisconsin			
Xcel Energy	August 2009	442-CE-169	Certificate of Necessity – Bay Front Gasifier
Montana			
Northwestern Energy	July 2024	2024.05.053	Electric Rate Case – Standby Rate Proposal

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY	)	Case No. PU-24-___
2025 ELECTRIC RATE INCREASE	)	
APPLICATION	)	

AFFIDAVIT OF
Steven W. Wishart

I, the undersigned, being first duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct 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.

Steven W. Wishart

State of Florida. County. Pinellas
Subscribed and sworn to before me, this 21 day of November, 2024.

Notary Public
My Commission Expires: July 6, 2025

CRYSTAL STEELE
MY COMMISSION # HH 115719
EXPIRES: July 6, 2025
Bonded Thru Notary Public Underwriters