Review of Jurisdictional Allocation Methods for Production and Transmission Costs

PREPARED FOR

The North Dakota Public Service Commission

SPONSORED BY

Xcel Energy

PREPARED BY

Toby Brown

Philip Hanser

April 2015

THE Brattle GROUP

This report was sponsored by Xcel Energy and prepared for the North Dakota Public Service Commission as required by the Settlement Agreement in Case No. PU-12-813. Direction was provided by Advocacy Staff of the North Dakota Public Service Commission regarding the key areas of focus.

All results and any errors are the responsibility of the authors and do not necessarily represent the opinions of the North Dakota Public Service Commission, Xcel Energy, or The Brattle Group, Inc.

Table of Contents

I. Executive Summary

A. Introduction

Xcel Energy provides electric service to customers in the States of North Dakota, South Dakota and Minnesota through its operating utility subsidiary Northern States Power Company—Minnesota (NSPM, or Xcel Energy). NSPM and Northern States Power—Wisconsin (NSPW), which serves customers in Wisconsin and Michigan, plan and operate an integrated generation and transmission system (the NSP System). This means that costs are incurred to ensure power is supplied reliably across the system and customers in each state benefit from the generation and transmission assets and operations located in all five states. Rates paid by customers in each state are regulated, however, by the respective state regulatory commissions.[1] For purposes of establishing rates in each state jurisdiction, it is necessary to share the costs of the integrated system that are in aggregate "caused" by loads and other conditions in each state and are to be recovered from customers through retail rates in each jurisdiction. A significant portion of the costs that are shared in this way include the investment-related costs associated with generation and transmission plant. The allocation of costs between NSPM and NSPW is governed by a FERC-approved Interchange Agreement.[2] The share of NSP costs allocated to NSPM must then be allocated to NSPM's three state jurisdictions.

As a provision of the Settlement Agreement in Case No. PU-12-813, the parties (Xcel Energy and the North Dakota Public Service Commission Advocacy Staff) agreed to commission a study of various methods that could potentially be used to assign a portion of the NSP System non-fuel generation- and transmission-related costs to the Xcel Energy's North Dakota jurisdiction for ratemaking purposes. The Brattle Group was retained to review the data, which can be used to allocate costs, analyze the results of various allocation methodologies, and prepare a report.

B. Allocation Methods Selected

With the assistance of Commission staff, Xcel Energy selected nine allocation methods to be analyzed in this study. Subsequently, we recommended that three additional methods be added to the analysis. For the most part, the methods ultimately selected were included because they are: 1) already used in North Dakota by a regulated utility; 2) used elsewhere in the industry for class or jurisdictional cost allocation; or 3) promoted by parties in the previous Xcel Energy rate proceeding in North Dakota as a potential allocation option.

---

1 The three state commissions that regulate NSPM are the North Dakota Public Service Commission, the South Dakota Public Utilities Commission, and the Minnesota Public Utilities Commission.

2 See *Restated Agreement to Co-ordinate Planning and Operations and Interchange Power and Energy between Northern States Power Company (Minnesota) and Northern States Power Company (Wisconsin)*, January 16 2001.

C. ASSESSMENT

To provide an overall assessment of the merits of each allocation method, we employed a set of criteria consistent with standard principles of cost allocation and reflective of the Commission's direction in its February 26, 2014 Order Accepting Settlement in Case No. PU-12-813. These criteria are:

A. *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?

B. *Stability*—Does the method produce cost allocation factors that do not overly fluctuate from year to year?

C. *Simplicity*—Is the allocation method understandable and simple to administrate?

D. *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?

E. *System Cost Recoverability*[3]—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?

To help assess how well each method performs under various criteria, ten years of historical actual, weather-normalized, and budgeted/forecasted demand and energy data from Xcel Energy were used to calculate each method's corresponding annual allocation of generation and transmission system costs attributable to North Dakota.

D. RECOMMENDATIONS AND CONCLUSIONS

Cost allocators apportion the investment costs historically undertaken by the utility and the utility's currently incurred expenses based upon the drivers of those costs, such as customer demand and energy use. 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.

---

3 The Settlement Agreement terms guiding this Study in Case No. PU-12-813 refer to "consistency among jurisdictions and administrative feasibility" as a secondary consideration (at p. 19).

In general, the EqP1CP and EqP4CP allocators provide sufficient recognition of both a jurisdiction's energy use and peak demand. They also take into account the overall generation fleet profile (eg, baseload, intermediate and peaking). Because 12CP and 36CP use data points from every month of the year, these methods also proxy the impacts of energy on costs. We note that over the period we analyzed EqP4CP performs similarly to 12CP and 36CP. In addition, 12CP is easier to calculate than the equivalent peaker methods, and is the method used throughout the region and in other Xcel jurisdictions. Accordingly, using the criteria in the study, we did not find compelling reasons to change the allocation method used in North Dakota.

We believe that our use of ten years of data is a reasonable time frame to have performed the analysis and represents an appropriate trade-off between contemporaneousness of data, which might suggest a shorter data series, and historical perspective, which would suggest a longer one. Further, the criteria that we have used for evaluating the allocators seems sensible and consistent with the Commission's past criteria. Based on those criteria, the 12 CP method does reasonably well. It appears to reflect the planning criteria and investments made by Xcel Energy to reliably meet its loads. It does not wildly fluctuate year to year. 12CP is straightforward to implement and easy to understand. Its predictability is good, due in part to its relative stability, but also because it does reasonably represent the cost drivers which Xcel Energy plans for. Lastly, changing from 12CP could affect Xcel Energy's cost recovery in uncertain ways and which would need to be accounted for in any modification of its cost allocation method.

II. Background

A. XCEL ENERGY OPERATIONS

Xcel Energy provides electric service to customers in the States of North Dakota, South Dakota, and Minnesota through its Northern States Power-Minnesota operating company (NSPM). Together with Northern States Power-Wisconsin (NSPW), which serves customers in Wisconsin and Michigan, the Company plans and operates an integrated generation and transmission system (the NSP System). As such, customers in each state benefit from the economies of scale and power supply diversity of a large, regional system. NSPM's customers and energy sales by state are as follows:

TABLE 1: 2013 NSP-MINNESOTA ELECTRIC OPERATIONS BY STATE JURISDICTION

	Customers	Customers (%)	MWh Sales	MWh (%)	MW Coincident Peak Demand	MW Coincident Peak Demand (%)
Minnesota	1,272,391	87.5%	30,937,829	87.7%	7,278	88.9%
North Dakota	92,820	6.4%	2,293,130	6.5%	420	5.1%
South Dakota	88,509	6.1%	2,036,795	5.8%	488	6.0%
NSPM Retail	1,453,720	100.0%	35,267,753	100.0%	8,186	100.0%

The generation and transmission costs of the NSP System are assigned to Xcel Energy's two NSP operating subsidiaries, NSPM and NSPW through a FERC-approved Interchange Agreement[4].

B. STUDY ORIGINS

In Xcel Energy's most recent North Dakota rate case (PU-12-813) the company filed a test year cost of service reflecting the continued application of the 12 month coincident peak (12CP) allocation method.[5] In direct testimony filed in the case, however, Advocacy Staff consultants recommended use of the single coincident peak (1CP) method instead. Ultimately, Advocacy Staff and Xcel Energy agreed that for determining rates in the current case, the 12CP method would continue to be used but that the parties would collaborate on a study of various jurisdictional allocation methods that could be used in North Dakota. An independent third-party (The Brattle Group, Inc.) was engaged to monitor the process, help evaluate the results, and assist in the development of the final Report. The final Settlement Agreement states, in part:

> *In light of the issues raised in the Rate Case related to the appropriate demand allocation methodology to be used for the purposes of setting the Company's North Dakota rates, the Parties agree that a study shall be performed to analyze the contribution of the Company's North Dakota jurisdiction toward the Company's overall system-wide production and transmission costs, and the*

[4] See footnote 2.

[5] The Company has used the 12CP allocator in North Dakota rate filings since 1993, when it was first approved by the NDPSC.

available demand allocation methodologies which may be implemented to reflect such cost causation (the Study).

The Parties intend the Study to be unbiased and thorough. To that end:

1. Scope. The Parties will determine, after consulting and seeking the input of the Commission, the appropriate scope of the Study, consistent with the terms of this Revised Second Amended Settlement. The scope of the Study will be to analyze a number of demand allocator methodologies and propose recommendations for the methodology or methodologies that most reasonably represent the cost causation of the North Dakota jurisdiction on the Company's overall system-wide production and transmission costs. Secondary consideration will be given to maintaining consistency among jurisdictions and administrative feasibility.

2. Independent Third-Party. The Parties will utilize the services of an independent third-party to assist in directing, monitoring, and evaluating the results of the Study. The Parties and the Commission must agree on the third-party to be used. Both Parties will fully cooperate with the third-party. Either Party may supplement the Study as appropriate to assure that the Commission has a full and complete record for its use.[6]

In May 2014 consensus was reached among the Parties on the Allocator Study work plan and schedule. During the summer, regulators in Minnesota and South Dakota were notified of the Study, Brattle was approved by the Parties and engaged to participate, and the selection of allocation methods to study was finalized. Brattle provided a cost allocation "primer" to the Commission in September 2014. Brattle presented a progress update to the North Dakota Commission in December 2014. This report represents the culmination of the past year's analysis, and was commissioned pursuant to the above terms of the Settlement Agreement.

C. JURISDICTIONAL COST ALLOCATION IN NORTH DAKOTA

The utility industry has employed various methods to use customer load characteristics – namely peak demands, energy sales, or a combination of both – to derive allocation factors to assign a multi-state utility's system-wide generation and transmission costs to each of its state jurisdiction within the overall system. By design, a jurisdictional allocation method will allocate 100 percent of the system costs to each of the individual state jurisdictions served by the system. The objective of any effective jurisdictional allocation method is to allocate costs to the constituent states consistent with the impact that each state's electrical load has on overall system planning, investment, and operations.

In North Dakota, the Commission has previously addressed the issue of jurisdictional cost allocation for Xcel Energy not only in the most rate case, but in prior rate cases in the early 1990's as well. Table 2 summarizes the previous 25 year history.

---

6 Revised Second Amended Comprehensive Settlement Agreement, Case No. PU-12-813, February 25,[h] 2014, pp. 18-19.

TABLE 2: CHRONOLOGY OF JURISDICTIONAL ALLOCATION METHODS FOR XCEL ENERGY IN ND

Case No.	Allocation Method Approved	Effected Period
	Summer & Winter Coincident Peak (used weighted average of summer, winter peaks)	Prior to March 1988
PU-400-87-6 (filed Jul. 7, 1987)	Peak & Average (approved Mar. 24, 1988). 12CP (approved Dec. 13, 1988). Note: The Mar. 24, 1988 Order was appealed and reconsidered by the NDSPC. Settlement was reached and approved. Settlement was appealed in District Court by an intervening party. After years of litigation the Dec. 13, 1988 Order was remanded to the NDPSC and later ratified (June 23, 1992).	March 1988 – Dec. 1988 Dec. 1988 – Dec. 1992
PU-400-91-112 (filed Mar. 8, 1991)	Weighted 12CP (approved Oct. 31, 1991).	Oct. 1991 – Jun. 1992
PU-400-92-399 (filed May 1, 1992)	Weighted 12CP (Approved Dec. 15, 1992). 12 CP (approved Apr. 7, 1993). Note: Dec. 15, 1992 Order was appealed and reconsidered by the NDPSC. New Order included revised allocator.	Dec. 1992 – Apr. 1993 Apr. 1993 – Jan. 2009
PU-07-776 (filed Dec. 7, 2007)	12 CP (approved Jan. 14, 2009)	Jan. 2009 – Feb. 2012
PU-10-657, PU-11-55 (filed Dec. 20, 2010)	12 CP (approved Feb. 29, 2012)	Feb. 2012 – Feb. 2014
PU-12-813 (filed Dec. 18, 2012)	12CP (approved Feb. 26, 2014)	Feb. 2014 – Dec. 2016

D. REGIONAL JURISDICTIONAL ALLOCATION METHODS

To provide additional context, a survey of the methods currently approved in North Dakota and its surrounding states was conducted. Table 3 summarizes, by state, the methods approved and in place for each regulated utility. For the most part, the jurisdictional factors have not been contested in recent rate proceedings, and for the most part each utility is presently able to establish rates in each state using a common allocation method. We were unable to find any recent comprehensive surveys of jurisdictional cost allocation practices across the entire U.S.

TABLE 3: CURRENT JURISDICTIONAL ALLOCATION METHODS USED IN 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	--	--	--

III. Allocation Methods Studied

A. SELECTION FACTORS

In the selection of allocation methods to include in the study, we focused primarily on methods that were:

A. Previously approved in North Dakota for regulated investor-owned utilities operating in the state,
B. Approved and being used in the surrounding Midwestern states of Montana, Minnesota, and South Dakota,
C. Proposed for use or discussed in Xcel Energy's most recent rate proceeding in North Dakota, or
D. Included in NARUC's 1992 manual of commonly used methods to allocate generation and transmission costs among customer classes and/or state jurisdictions.

Xcel Energy, the Brattle Group and Advocacy staff discussed the scope of the study in September 2014 and reviewed at that time the nine methods to be studied. We later recommended that three additional methods be included.

Table 4 identifies the twelve methods and corresponding selection factors (A through D above) for each respective method.

TABLE 4: ALLOCATION METHODS SELECTED FOR THIS STUDY

METHOD		RELEVANT SELECTION FACTOR
Peak Demand Methods		
1.	One Month Coincident Peak (1CP)	C
2.	Three Month Coincident Peak (3CP)	D
3.	Four Month Coincident Peak (4CP)	D
4.	Summer/Winter Coincident Peak (SWCP)	A,D
5.	Twelve Month Coincident Peak (12CP)	A,B,C,D
6.	Weighted 12 Month Coincident Peak (W12CP)	A,C
7.	Thirty-Six Month Coincident Peak (36CP)	A
Peak/Energy Methods		
8.	Equivalent Peaker with 1CP (EQ1CP)	A,B,C
9.	Equivalent Peaker with 4CP (EQ4CP)	A,C
10.	Equivalent Peaker with 12CP (EQ12CP)	A,C
11.	Average and Excess (AED)	D
12.	Peak and Average (PkAv1CP)	D

B. COST ALLOCATION DISCUSSION

Each of the jurisdictional allocation methods selected allocates a jurisdiction's contribution to the overall system cost structure in a different way. According to the NARUC Cost Allocation Manual, methods that utilize a peak demand approach are characterized by two features: 1) all production costs are classified as demand-related; and 2) these costs are allocated to jurisdictions using factors that measure the jurisdiction's contribution to system peak demand. The variations in the demand-based methods are generally around the number of system peaks analyzed.[7] The NARUC manual also highlights two important facets of demand-based methods: 1) the number of system peak demand hours used can have a significant effect on the allocation of revenue requirements; and 2) the greater the number of hours used, the more the allocation will reflect a jurisdiction's energy requirements.

According to the NARUC manual, there is also evidence that energy loads, as opposed to a measure of demand, are a major determinant of production plant costs.[8] Total energy influences production plant choice. This is particularly evident for a utility that has made significant

---

7 See Electric Utility Cost Allocation Manual section "A. Peak Demand Methods," page 41.

8 See Electric Utility Cost Allocation Manual section "B. Energy Weighting Methods," page 49.

investments in higher-cost baseload generation (higher cost per unit of capacity) to provide lower cost energy in all hours of the year. One way to incorporate an energy weighting in the allocation factor is to classify a portion of production plant costs as energy-related and allocate these costs to jurisdictions on the basis of energy consumption.

With respect to transmission costs, costs are often allocated on a basis similar to the way production costs are allocated.[9] When this occurs, it is because the transmission investments are typically viewed as "extensions" of the production system. In other words, the planning and operation of both production and transmission assets are linked, and hence the major drivers of production costs tend to impact transmission cost as well. Alternatively, the transmission system may have reliability requirements that necessitate planning beyond viewing the transmission as an extension of the production system, particularly for systems which serve geographically diverse areas or which have significant interconnections to other transmission systems, as is the case for Xcel Energy.

While each method reflects a different view of how North Dakota electric operation impacts the planning and operation of the integrated system, all methods calculate an allocation factor by dividing a North Dakota load value—typically a "usage" expressed in demand, energy, or a combination thereof—by the same value representing the overall operating company (i.e., NSPM, the sum of North Dakota, South Dakota, and Minnesota jurisdictions).

The methods selected for this study have been compared and contrasted using the set of assessment criteria listed above in the summary section. We analyzed, historical data from 2004 through 2013, as well as forecasted (budget) load information from 2005 through 2015. Monthly peak demand and energy data, by jurisdiction, are included in Appendix E to this study.

The twelve methods selected for analysis are more fully defined and explained below.

C. METHOD DESCRIPTIONS

The following presents a detailed explanation of how the allocation factor from each allocation method is derived. A sample set of data from 2013 is shown in each case to demonstrate how the calculation is performed. Allocation factor results and comparisons of the results across time and by methods are discussed later in this report and are included in the Appendix.

1. Single Month Coincident Peak Demand (1CP)

The 1CP method targets the single hour in which the overall system peak demand occurs in a given year, using the NSPM and jurisdictional coincident demands during the same hour to derive the allocation factor.

The one hour in which the NSPM system demand is highest for the year must be first identified. The corresponding demands in each of the jurisdictions during the same hour the system peaked

---

9 See Electric Utility Cost Allocation Manual section "II. Methods of Allocating Transmission Plant", page 75.

are then determined (i.e., the "coincident" peak demands). The allocator for each NSPM jurisdiction is derived by dividing the jurisdiction's coincident peak demand by the overall NSPM peak demand.

Formula

$$1CP\ Allocator = Coincident\ Peak\ Demand_{Jur}\ \div Peak\ Demand_{NSPM}$$

Where $Coincident\ Demand_{(1),Jur}$ is determined as follows:

$Coincident\ Pk\ Demand_{Jur}$ = Maximum($Coinc\ Pk\ Dem_{Jan,Jur}$ … $Coinc\ Pk\ Dem_{Dec,Jur}$)

And where $Peak\ Demand_{NSPM}$ is determined as follows:

$Peak\ Demand_{NSPM}$ = Maximum($Pk\ Dem_{Jan,NSPM}$ … $Pk\ Dem_{Dec,NSPM}$)

Example

Assuming that the coincident peak demands and NSPM system monthly peaks are as follows for a given year (in KWs):

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

In this example, the NSPM system peak month is August. Applying transmission loss factors corresponding to each state to convert the generator demands to demands evident at the retail distribution level; (i.e., demands at the "high voltage" side of distribution substation) results in the 1CP calculation as follows:

1CP	Peak Demand	Trans Loss Adjustment	Adjusted Pk Demand	Allocation Factor
MN Jur.	7,278,146	95.800%	6,972,464	88.814%
ND Jur.	419,851	93.410%	392,183	4.996%
SD Jur.	487,924	99.610%	486,021	6.191%
NSPM Co.	8,185,922		7,850,669	100.000%

Notes

The 1CP method relies only on the single annual system peak, without consideration for customer loads during the other months of the year. By definition, it assumes all generation and transmission has been built solely for the purpose of meeting the system peak, and that each jurisdiction's contribution to the overall system's fixed generation and transmission costs are best reflected by how much they contribute to the overall system peak.

2. Three Month Coincident Peak Demand (3CP)

The 3CP uses monthly jurisdictional demand data from the three (typically consecutive) months of the year with the highest peak demands.

To calculate the jurisdictional allocation, the hours of highest demand in each of the three months in which the highest system demand is recorded are selected. The corresponding coincident demands in each of the three NSPM jurisdictions (i.e., during the same hour the system peaked in each of those three months) are determined. For each jurisdiction and for the NSPM total, the three coincident demand amounts are summed. The allocator for each jurisdiction is determined by dividing its three month total by the NSPM three month total.

Formula

$$3CP\ Allocator = \frac{Coinc\ Dem_{(1),Jur} + Coinc\ Dem_{(2),Jur} + Coinc\ Dem_{(3),Jur}}{Pk\ Dem_{(1),NSPM} Pk\ Dem_{(2),NSPM} + Pk\ Dem_{(3),NSPM}}$$

Example

Assuming that the coincident peak demands and NSPM system monthly peaks are as follows for a given year (in KWs):

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 3 peak months to sum would be June, July, and August, and the 3CP calculation would be as follows:

3CP	Sum of 3 Peaks	Trans Loss Adjustment	Adj Sum of 3 Peaks	Allocation Factor
MN Jur.	20,403,513	95.800%	19,546,566	88.482%
ND Jur.	1,268,524	93.410%	1,184,928	5.364%
SD Jur.	1,364,746	99.610%	1,359,424	6.154%
NSPM Co.	23,036,784		22,090,918	100.000%

Notes

Like the 1CP, this method is based on the notion that generation and transmission assets have been planned and built for the purpose of meeting the system's annual peak load, without regard for the possibility that investments in higher cost baseload generation were made to provide low-cost energy throughout the year.

3. Four Month Coincident Peak Demand (4CP)

The 4CP method uses monthly jurisdictional demand data from each of the four months of the year with the highest total system peak demands, thereby extending the "seasonal" approach of the 3CP method by another month.

To calculate the jurisdictional allocation, the hours of the highest demand in each of the four months in which the highest system demand is recorded are selected. The corresponding coincident demands in each of the three NSPM jurisdictions (i.e., during the same hour the system peaked in each of those four months) are then determined. For each jurisdiction and for the NSPM total, the four coincident demand amounts are summed. The allocator for each jurisdiction is determined by dividing its four month total by the NSPM four month total.

Formula

$4CP\ Allocator$

$$= \frac{Coinc\ Dem_{(1),Jur} + Coinc\ Dem_{(2),Jur} + Coinc\ Dem_{(3),Jur} + Coinc\ Dem_{(4),Jur}}{Pk\ Dem_{(1),NSPM} + Pk\ Dem_{(2),NSPM} + Pk\ Dem_{(3),NSPM} + Pk\ Dem_{(4),NSPM}}$$

Example

Assuming that the coincident peak demands and NSPM system monthly peaks are as follows for a given year (in KWs):

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 4 peak months to sum would be June, July, August, and September and the 4CP calculation would be as follows:

4CP	Sum of 4 Peaks	Trans Loss Adjustment	Adj Sum of 3 Peaks	Allocation Factor
MN Jur.	26,841,069	95.800%	25,713,744	88.585%
ND Jur.	1,599,329	93.410%	1,493,933	5.147%
SD Jur.	1,826,656	99.610%	1,819,532	6.268%
NSPM Co.	30,267,054		29,027,209	100.000%

Notes

The 4CP method is an extension of the seasonal approach of the 3CP and also has found application in systems where the annual peak demand can occur anytime during a particular season. The 4CP covers a full four month summer or winter season. Like the 1CP and 3CP, this method assumes that all generation and transmission have been planned and built for the purpose of meeting the system's annual peak load.

4. Summer/Winter Coincident Peak Demand (SWCP)

The Summer/Winter CP method reflects the effects of two distinct seasonal peaks. It finds applicability when the summer and winter peaks both significantly impact the utility's planning decisions.

This method requires a definition of the summer and winter seasons, using three or perhaps four, consecutive months for each season. As with other peak demand methods, the hours must be determined in which the system peak demand occurs for each month of the defined summer and winter periods. Then the corresponding coincident demands for each of the NSPM jurisdictions during the same summer and winter hours must be determined. The total of the coincident peak demands for each of the summer months is added together to the total coincident peak demands for the winter months for each jurisdiction and divided by the sum of summer peak demand and winter peak demand for the NSPM system. For purposes of this description, we use the sum of the averages of the summer and winter peaks, consistent with the approach described in the NARUC manual.

Formula

Following the example data used above, we will define the summer season as a 3 month period from July through September. The winter season will be defined as a 3 month period from December through February.

$$Summer/Winter\ Peak\ Allocator = \frac{\left(Coinc\ Dem_{S,Jur} + \ Coinc\ Dem_{W,Jur}\right)}{(\ Pk\ Demand_{S,NSPM} + \ Pk\ Demand_{W,NSPM})}$$

Where summer coincident demand is:

$$Coincident\ Dem_{S,Jur} \ = \ Coinc\ Dem_{Jul,Jur} + \ Coinc\ Dem_{Aug,Jur} + Coinc\ Dem_{Sep,Jur}$$

And winter coincident demand is:

$$Coincident\ Dem_{W,Jur} \ = \ Coinc\ Dem_{Dec,Jur} + \ Coinc\ Dem_{Jan,Jur} + Coinc\ Dem_{Feb,Jur}$$

Where summer system peak demand is:

$$Pk\ Demand_{S,NSPM} \ = \ Pk\ Dem_{Jul,NSPM} + \ Pk\ Dem_{Aug,NSPM} + Pk\ Dem_{Sep,NSPM}$$

And winter system peak demand is:

$$Pk\ Demand_{W,NSPM} = Pk\ Dem_{Dec,NSPM} + Pk\ Dem_{Jan,NSPM} + Pk\ Dem_{Feb,NSPM}$$

Example

Assuming that the coincident peak demands and NSPM system monthly peaks are as follows for a given year (in kWs):

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

In this example, the summer system and coincident peaks from July, August, and September are averaged, and the winter system and coincident peaks from December, January, and February are averaged. The resulting summer and winter averages for the jurisdiction and system are each separately summed.

The Summer/Winter Peak calculation would be as follows:

SWP	Sum of Avg S, W Peaks	Trans Loss Adjustment	Adj Sum of S, W Peaks	Allocation Factor
MN Jur.	11,587,840	95.800%	11,101,151	87.692%
ND Jur.	842,313	93.410%	786,804	6.215%
SD Jur.	774,296	99.610%	771,276	6.093%
NSPM Co.	13,204,449		12,659,231	100.000%

Notes

The SWCP approach may be applicable when a utility (typically in a northern climate) experiences two distinct peaks of significant magnitude, usually occurring during the summer and winter months. An alternative approach to using multiple monthly peaks during each season would be to use the single highest peak in each of the defined summer and winter seasons to derive the final factor.

5. 12 Month Coincident Peak Demand (12CP)

The 12CP method uses all twelve monthly system and jurisdictional coincident peak demands for the given year.

To calculate jurisdictional allocation, the hour of highest system demand in each month is selected. The corresponding peak demands in each of the NSPM jurisdictions (i.e., during the same hour the system peaked) are then determined. For each jurisdiction and for the NSPM total, the twelve coincident demand amounts are summed. The allocator for each jurisdiction is determined by dividing its twelve month total by the NSPM twelve month total.

Formula

$$12CP\ Allocator = \left(\sum_{Jan}^{Dec} Dem_{Month,Jur}\right) \div \left(\sum_{Jan}^{Dec} Dem_{Month,NSPM}\right)$$

Where:

$$Coinc\ Demand_{Month,Jur} = Jurisdictional\ demand\ during\ hour\ of\ month's\ system\ peak$$

And,

$$Peak\ Demand_{Month,NSPM}$$
$$= System\ peak\ demand\ for\ the\ month\ Month, NSPM\ for\ each\ month\ of\ the\ year$$

Example

Assuming that the coincident peak demands and NSPM system monthly peaks are as follows for a given year (in kWs):

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%

Notes

Because the 12CP method is based on demands in all 12 months of the year, there are enough data points to reflect some of the effect of planning to meet energy requirements at the lowest cost in addition to meeting demands throughout the year. 12CP is often used by utilities to reflect the need to maintain a sufficient reserve margin and/or Loss of Load Probability (LOLP) across all months. This method is common in the industry having been adopted by FERC in the late 1980's. It is currently used by Xcel Energy to allocate NSPM system costs.

6. Weighted 12 Month Coincident Peak Demand (W12CP)

The weighted 12CP method is a derivative of the 12CP method whereby additional weighting is given to the months with the highest system peak demands. Before the 12 month system peak demands and the coincident jurisdictional peak demands are summed, each monthly demand is multiplied by a weighting factor. The weighting factor for each month is the ratio of the system peak demand for the given month compared to the lowest monthly system peak demand for the year (such that the weighting is equal to 1 for the month with the lowest system peak demand).

Formula

$$Wtd\ 12CP\ Allocator = \left(\sum_{Jan}^{Dec} w_{month} \times Coinc\ Dem_{Month,Jur}\right) \div \left(\sum_{Jan}^{Dec} w_{month} \times Peak\ Dem_{Month,NSPM}\right)$$

Where weighting factor w_{month} is:

$$w_{month} = Peak\ Dem_{month,NSPM} \div Minimum(Peak\ Dem_{Jan,NSPM}, Dem_{Feb,NSPM}, \dots, Dem_{Dec,NSPM})$$

Where:

$$Coinc\ Demand_{Month,Jur} = Jurisdictional\ demand\ during\ hour\ of\ month's\ system\ peak$$

And,

$$Peak\ Demand_{Month,NSPM} = System\ peak\ demand\ for\ the\ month\ Month, NSPM\ for\ each\ month\ of\ the\ year$$

Example

Assuming that the coincident peak demands and NSPM system monthly peaks are as follows for a given year (in kWs). The weighting factors are shown below the NSPM system monthly peaks. The second table shows the weighted monthly demands, after the actual demands have been multiplied by each month's weighting factor.

	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
Wtg Factor:	1.17	1.12	1.05	1.00	1.14	1.45	1.67	1.72	1.52	1.07	1.10	1.20	

Wtd Demand	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
MN Jur.	5,620,948	5,131,096	4,604,688	4,154,462	5,426,752	8,808,006	11,807,831	12,535,436	9,793,244	4,793,682	4,985,965	5,958,325	83,620,433
ND Jur.	489,242	457,641	372,589	349,803	354,835	579,655	751,771	723,126	503,242	313,878	404,555	516,984	5,817,321
SD Jur.	375,687	338,101	292,730	248,528	411,982	603,006	771,942	840,371	702,689	315,008	326,712	401,486	5,628,242
NSPM Co.	6,485,877	5,926,838	5,270,007	4,752,793	6,193,569	9,990,667	13,331,544	14,098,933	10,999,174	5,422,567	5,717,232	6,876,794	95,065,997

The W12CP calculation would be as follows:

W12CP	Sum of Mo. Peaks	Trans Loss Adjustment	Adj Sum of S, W Peaks	Allocation Factor
MN Jur.	83,620,433	95.800%	80,108,375	87.888%
ND Jur.	5,817,321	93.410%	5,433,960	5.962%
SD Jur.	5,628,242	99.610%	5,606,292	6.151%
NSPM Co.	95,065,997		91,148,627	100.000%

Notes

The W12CP method was proposed by the NDPSC staff during Case No. PU-400-91-112. It is not clear how the weighting methodology used in this approach correlates with each jurisdiction's impact on system planning and costs. We are not aware of this method being used elsewhere.

7. 36 Month Coincident Peak Demand (36CP)

The 36CP method is essentially computed the same way as the 12CP method except that 36 months of system peak and coincident demand data are used.

Formula

$$36CP\ Allocator = \sum_{Yr1}^{Yr3}\left(\sum_{Jan}^{Dec} Coinc\ Dem_{Month,Jur}\right) \div \sum_{Yr1}^{Yr3}\left(\sum_{Jan}^{Dec} Peak\ Dem_{Month,NSPM}\right)$$

For ratemaking, Yr 3 is the forecasted test year, Yr 2 is the year previous to the test year (forecasted) and Yr 1 is the historical year (since the Yr 3 rate case test year is typically prepared beginning early the year before, in Yr 2, actual demands are not yet available for all of Yr 2), and where:

$$Coinc\ Demand_{Month,Jur} = Jurisdictional\ demand\ during\ hour\ of\ month's\ system\ peak$$

And,

$$Peak\ Demand_{Month,NSPM}$$
$$= System\ peak\ demand\ for\ the\ month\ Month, NSPM\ for\ each\ month\ of\ the\ year$$

Example

Assume that the coincident peak demands and NSPM system monthly peak demands (in kWs) are as follows for a given 36 month period.

2011 Actual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
MN Jur.	4,847,661	4,766,735	4,513,420	4,216,962	4,702,910	6,936,044	7,215,460	6,265,403	6,525,027	4,800,869	4,522,601	4,699,973	64,013,066
ND Jur.	403,752	389,716	380,715	312,764	264,818	328,814	379,852	433,870	373,848	349,880	349,875	374,829	4,342,733
SD Jur.	313,998	312,703	293,581	248,831	261,874	418,907	476,917	444,911	454,896	309,902	288,834	309,823	4,135,177
NSPM Co.	5,565,412	5,469,154	5,187,716	4,778,557	5,229,601	7,683,765	8,072,229	7,144,183	7,353,771	5,460,651	5,161,310	5,384,626	72,490,975

2012 Forecast	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
MN Jur.	4,894,710	4,766,337	4,585,257	4,373,999	5,390,827	6,342,874	6,360,617	6,293,937	5,936,680	4,524,661	4,833,899	5,060,289	63,364,086
ND Jur.	411,286	392,888	342,798	314,759	319,033	376,943	331,707	386,300	364,647	313,127	376,215	430,949	4,360,651
SD Jur.	335,723	291,021	292,891	253,709	345,138	398,395	420,753	431,456	381,271	258,222	296,753	337,039	4,042,372
NSPM Co.	5,641,719	5,450,246	5,220,946	4,942,467	6,054,998	7,118,211	7,113,076	7,111,693	6,682,598	5,096,010	5,506,867	5,828,278	71,767,109

2013 Forecast	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
MN Jur.	4,772,950	4,637,538	4,422,958	4,171,717	5,384,966	6,404,884	6,396,444	6,305,151	5,980,461	4,628,964	4,580,846	4,793,538	62,480,417
ND Jur.	396,111	400,990	344,834	316,381	305,174	366,900	345,220	409,827	403,276	348,717	370,703	434,187	4,442,319
SD Jur.	316,533	300,413	295,796	258,318	341,097	399,289	431,462	473,288	438,474	296,561	295,090	334,445	4,180,766
NSPM Co.	5,485,595	5,338,940	5,063,587	4,746,416	6,031,237	7,171,073	7,173,127	7,188,266	6,822,212	5,274,242	5,246,639	5,562,170	71,103,503

The 36CP calculation would be as follows:

36CP	Sum of 36 Peaks	Trans Loss Adjustment	Adj Sum of 36 Peaks	Allocation Factor
MN Jur.	189,857,569	95.800%	181,883,551	88.091%
ND Jur.	13,145,704	93.410%	12,279,402	5.947%
SD Jur.	12,358,315	99.610%	12,310,117	5.962%
NSPM Co.	215,361,588		206,473,071	

Notes

The 36CP is used in the FERC-approved NSPM/NSPW Interchange Agreement Agreement. We are not aware of this method being used elsewhere.

8. Equivalent Peaker Using Single Peak Demand (EQ1CP)

Equivalent Peaker methods are fundamentally based on generation expansion planning practices which consider meeting peak demands and serving low-cost energy in determining the need and type of additional generation. The EQ1CP method requires the initial step of dividing, or "stratifying," a utility's generation investment-related costs into two categories: costs associated with meeting capacity requirements (peak demand) and costs associated with providing low-cost energy (such as from a baseload facility). Under the EQ1CP, costs associated with meeting peak demands are then allocated to jurisdictions using the 1CP method, and costs associated with providing low-cost energy are allocated to jurisdictions based on the energy use (MWhs) in each jurisdiction. The stratification of NSPM's generation resources into "capacity-related" and "energy-related" categories is described and shown in Appendix D.

Formula

$$Equivalent\ Peaker\ 1CP_{Jur} = \%\ Peaking\ \times 1CP_{Jur} + (1 - \%\ Peaking) \times Energy\ Factor_{Jur}$$

Where Energy $Factor_{Jur}$ is defined:

$$Energy\ Factor_{Jur} = (Energy\ Use_{Jur} \div Energy\ Use_{NSPM})$$

And where *% Peaking* is the aggregate fraction of generation investment planned and built to meet peak demands. This ratio is computed by dividing the utility's peaking plant average investment cost per kW by the average investment costs per kW for each of its other types of generating plants (nuclear, fossil, combined cycle, hydro, and/or wind). The capacity, or peaking-related portion of total production costs is based on the ratio of combustion turbine or peaking plant fixed costs (in $/kW) to the fixed costs for each other type of generation (in $/kW). A combustion turbine is considered the generation source with the lowest capital cost. Any capital cost per kW over and above the combustion turbine cost per kW are considered to be incurred to provide lower-cost energy throughout the year. The corresponding ratios for each resource type are then weighted by total investment to arrive at company aggregate ratios of capacity- and energy-related costs.

Example

If we use the same 1CP factor example shown previously, and assume that the stratification of generation indicates that 32.26 percent of generation investment is in place to meet peak demands and the remaining 67.74 percent is for generating low-cost energy throughout the year, then the EQ1CP allocation factor is calculated as follows:

EQP1CP								
	1CP Factor	% Gen Pking	Wtd 1CP Factor	Energy Use	Energy Factor	% Gen Energy	Wtd Energy Factor	Allocation Factor*
MN	88.814%	32.26%	28.651%	31,882,826	87.651%	67.74%	59.375%	88.026%
ND	4.996%	32.26%	1.612%	2,364,949	6.502%	67.74%	4.404%	6.016%
SD	6.191%	32.26%	1.997%	2,126,776	5.847%	67.74%	3.961%	5.958%
NSPM Co.	100.000%	32.26%	32.260%	36,374,552	100.000%	67.74%	67.740%	100.000%

*sum of weighted 1CP factor and weighted energy factor

Notes

The EQ1CP method recognizes that not all generating plants are built to simply meet peak load need. This is reflected in the allocation of peaking capacity costs using peak demand data and the allocation of the additional investment costs of baseload plants using energy data. As a result, well over half of production plant costs are typically defined as energy- related, so jurisdictions with higher load factors will typically see more system costs allocated to them than through a demand-based allocator.

Because the logic of the EQ1CP method is based on separating generation plant costs in recognition that the generating resources reflects the goal of optimally meeting peak demands while minimizing lower-cost energy throughout the year, the method may be teamed with another allocation factor to allocate system transmission costs.

9. Equivalent Peaker Using 4 Month Peak Demand (EQ4CP)

Like the EQ1CP method, the EQ4CP method requires the initial step of dividing a utility's generation investment-related costs into two categories: cost associated with meeting peak demand and costs associated with providing low-cost energy. Costs associated with meeting peak demands are then allocated to jurisdictions using the more seasonal 4CP method, and costs associated with providing low-cost energy are allocated to jurisdictions based on energy use (MWhs) in each jurisdiction.

Formula

$$Equivalent\ Peaker\ 4CP_{Jur} = \%\ Peaking\ \times 4CP_{Jur} + (1 -\ \%\ Peaking) \times Energy\ Factor_{Jur}$$

Where Energy $Factor_{Jur}$ is defined:

$Energy\ Factor_{Jur} = (Energy\ Use_{Jur} \div Energy\ Use_{NSPM})$

And where *% Peaking* is as defined above.

Example

If we use the same 4CP factor example shown previously, and assume that the stratification of generation indicates that 32.26 percent of generation investment is in place to meet peak demands and the remaining 67.74 percent is for generating low-cost energy throughout the year, then the EQ4CP allocation factor is calculated as follows:

EQ4CP	4CP Factor	% Gen Pking	Wtd 4CP Factor	Energy Use	Energy Factor	% Gen Energy	Wtd Energy Factor	Allocation Factor*
MN	88.585%	32.26%	28.578%	31,882,826	87.651%	67.74%	59.375%	87.953%
ND	5.147%	32.26%	1.660%	2,364,949	6.502%	67.74%	4.404%	6.065%
SD	6.268%	32.26%	2.022%	2,126,776	5.847%	67.74%	3.961%	5.983%
NSPM Co.	100.000%	32.26%	32.260%	36,374,552	100.000%	67.74%	67.740%	100.000%

*sum of weighted 4CP factor and weighted energy factor

Notes

The EQ4CP method is similar in structure to the EQ1CP; the additional data points create slightly more complexity but the use of 4 monthly demands (basically a season) to determine an appropriate set of coincident demands mitigates the volatility inherent in using a single hour to capture system peak and coincident demands within the jurisdiction.

10. Equivalent Peaker Using 12 Month Peak Demand (EQ12CP)

Like the EQ1CP and EQ4CP methods, the EQ12CP method requires the initial step of dividing a utility's generation investment-related costs into two categories: costs associated with meeting peak demand and costs associated with providing low-cost energy. Costs associated with meeting peak demands are then allocated to jurisdictions using the 12CP method, and costs associated with providing low-cost energy are allocated to jurisdictions based on energy use (MWhs) in each jurisdiction.

Formula

$$Equivalent\ Peaker\ 12CP_{Jur} = \%\ Peaking\ \times 12CP_{Jur} + (1 - \%\ Peaking) \times Energy\ Factor_{Jur}$$

Where Energy $Factor_{Jur}$ is defined:

$Energy\ Factor_{Jur} = (Energy\ Use_{Jur} \div Energy\ Use_{NSPM})$

And where *% Peaking* is as defined above.

Example

If we use the same 12CP factor example shown previously, and assume that the stratification of generation indicates that 32.26 percent of generation investment is in place to meet peak demands and the remaining 67.74 percent is for generating low-cost energy throughout the year, then the EQ12CP allocation factor is calculated as follows:

EQ12CP	12CP Factor	% Gen Pking	Wtd 12CP Factor	Energy Use	Energy Factor	% Gen Energy	Wtd Energy Factor	Allocation Factor*
MN	87.763%	32.26%	28.312%	31,882,826	87.651%	67.74%	59.375%	87.687%
ND	6.110%	32.26%	1.971%	2,364,949	6.502%	67.74%	4.404%	6.375%
SD	6.128%	32.26%	1.977%	2,126,776	5.847%	67.74%	3.961%	5.937%
NSPM Co.	100.000%	32.26%	32.260%	36,374,552	100.000%	67.74%	67.740%	100.000%

*sum of weighted 12CP factor and weighted energy factor

Notes

The EQ12CP method is similar in structure to the EQ1CP and EQ4CP methods. But given that it already uses an energy allocator for over half of the fixed costs, the use of the 12 monthly peak demands may place too much emphasis on energy as a driver for generation investment (as the use of 12 monthly demands begins to proxy some of the allocation attributes of energy use).

11. Average and Excess Demands (AED)

By allocating system costs using average demands (which is mathematically equivalent to using energy consumption) and non-coincident peak demands, the Average and Excess Demand method also considers that both peak demands and energy use influence the planning of and investment in system generation costs. However, the calculations involved are not as complex as the Equivalent Peaker methods in that they do not require a stratification step. Instead, this method splits system investment between peaking and energy by assuming that the utility's overall load factor (i.e., the energy produced by the system expressed as a percentage of the maximum energy output) represents the portion of costs associated with energy. As such, the amount attributed to capacity is represented by the reciprocal of the load factor. For NSPM, this method would result in about 53 percent of the costs being allocated to jurisdictions based on their energy use, and the remaining 47 percent (capacity) would be allocated based on how much each jurisdiction's annual non-coincident peak exceeded its annual average demand.

Formula

$$Avg\&Excess_{Jur} = \left(\frac{Avg\ Dem_{Jur}}{Avg\ Dem_{NSPM}}\right) \times Load\ Factor_{NSPM} + \left(\frac{Excess\ Dem_{Jur}}{Excess\ Dem_{NSPMr}}\right) \times (1 - Load\ Factor_{NSPMr})$$

Average Demand for both jurisdiction and system is defined as:

$$Avg\ Demand \quad = Energy\ Used \quad \div\ 8{,}760$$

It should be noted that the ratio of $Avg\ Demand_{Jur}$ to $Avg\ Demand_{NSPM}$ is equivalent to the ratio of $Energy_{Jur}$ to $Energy_{NSPM}$ (i.e., the $Energy\ Factor_{Jur}$).

Excess Demand at the jurisdictional and system level is defined as:

$$Excess\ Demand_{NSPM} = Peak\ Demand_{NSPM} - Avg\ Demand_{NSPM}$$

$$Excess\ Demand_{Jur} = Non\text{-}Coinc\ Peak\ Demand_{Jur} - Avg\ Demand_{Jur}$$

Load Factor is defined as:

$$Load\ Factor_{Sys} = Avg\ Demand_{Sys} \div Peak\ Demand_{Sys}$$

$$Load\ Factor_{Jur} = Avg\ Demand_{Jur} \div Non - Coinc\ Peak\ Demand_{Jur}$$

Example

Using the same data as shown in the example for Method 10, we can calculate the average demands by dividing the energy use by 8,760 (the number of hours in a year). If the system load factor is 52.892 percent and the non-coincident peak demands are as shown in the 6th column below, the AED allocation factor is calculated as follows:

AED	Avg Demand	Avg Dem Ratio	Sys Load Factor	Wtd Avg Dmd Ratio	NonCoinc Pk Dem	Excess Demand	Exc Dem Ratio	1-Ld Factor	Wtd Exc Dmd Ratio Factor*	Allocation
MN	3,640	87.651%	52.892%	46.360%	6,978	3,338	89.122%	47.108%	41.984%	88.344%
ND	270	6.502%	52.892%	3.439%	423	153	4.089%	47.108%	1.926%	5.365%
SD	243	5.847%	52.892%	3.093%	497	254	6.788%	47.108%	3.198%	6.290%
NSPM Co.	4,152	100.000%	52.892%	52.892%	7,898	3,746	100.000%	47.108%	47.108%	100.000%

*Sum of weighted Avg Demand ratio and weighted Excess Demand ratio

Notes

Like the Equivalent Peaker methods, this method uses both energy and demand inputs to recognize a utility's investments resulting from its planning goal of meeting peak demand and providing low cost energy. The AED method does not, however, directly consider the profile of a utility's generation fleet to determine how much capital costs should be considered as capacity-related. So, while the categorization between energy and capacity costs using load factor seems "directionally" reasonable, it may not be as precise as the equivalent peaker approach.

It should be noted that the AED method relies on a single peak demand hour to determine "excess demand" upon which to allocate the capacity portion of costs.

12. Peak and Average Demand using 1CP (PkAv1CP)

The Peak and Average 1CP method uses a weighted average of the 1CP allocator and an energy allocator. The allocator is similar to the equivalent peaker methods in that it incorporates both energy and demand allocators to allocate the costs assigned to energy and capacity, respectively. However, the PkAv1CP method determines the capacity portion of the costs to be the ratio of the system annual peak demand to the sum of the system annual peak demand and the system *average* demand. The energy-related costs are then the reciprocal of this ratio (or the ratio of the annual system average demand to the sum of the system annual peak demand and the annual system average demand).

Formula

$$Peak\&Avg\ 1CP_{Jur}\ Allocator$$
$$= 1CP\ Allocator_{Jur} \times Peak\ Demand\ Factor_{NSPM}$$
$$+ Average\ Demand\ Allocator_{Jur} \times Average\ Demand\ Factor_{Jur}$$

Where Peak Demand Factor$_{NSPM}$ is defined as:

$$Peak\ Demand\ Factor_{NSPM} = \frac{Peak\ Demand_{NSPM}}{Peak\ Demand_{NSPM} + Avg\ Demand_{NSPM}}$$

And where Average Demand Factor$_{NSPM}$ is defined as:

$$Avg\ Demand\ Factor_{NSPM} = \frac{Avg\ Demand_{NSPM}}{Peak\ Demand_{NSPM} + Avg\ Demand_{NSPM}}$$

Example

Using the same data as shown in the example for Methods 10 and 11, we can calculate the average demands by dividing the energy use by 8,760 (the number of hours in a year). If the system and coincident peaks are as shown in the 6th column below, the PkAv1CP allocation factor is calculated as follows:

PkAv1CP	Avg Demand	Avg Dem Ratio	Sys Avg Dem Factor	Wtd Avg Dmd Ratio	Coinc Pk Dem	Pk Dem Ratio	Sys Pk Dem Factor	Wtd Pk Dmd Ratio	Allocation Factor*
MN	3,640	87.651%	34.594%	30.322%	6,972	88.814%	65.406%	58.089%	88.412%
ND	270	6.502%	34.594%	2.249%	392	4.996%	65.406%	3.267%	5.517%
SD	243	5.847%	34.594%	2.023%	486	6.191%	65.406%	4.049%	6.072%
NSPM Co.	4,152	100.000%	34.594%	34.594%	7,851	100.000%	65.406%	65.406%	100.000%

*Sum of weighted Avg Demand ratio and weighted Excess Demand ratio

Notes

As with the AED allocator, the method to split costs between energy and capacity is relatively straightforward but is not necessarily linked to the utility's underlying generation profile as is the case with the Equivalent Peaker methods. Again, note that with the AED methods, the PkAv1CP method relies on a single peak demand data point to, in this case, allocate capacity-related costs.

D. KEY ATTRIBUTES

We begin our assessment of the methods with a discussion of some of the key characteristics of each method, organized in the form of a list of positive aspects and areas of concern. This section will be followed by the results of our analysis using five specific criteria.

1. Single Month Coincident Peak Demand (1CP)

Positive Aspects

- Very simple calculation (uses only one annual demand hour for the year) and has an intuitive basis, i.e., that generating and transmission assets are secured to meet the highest demand.

Areas of Concern

- The 1CP method is a very narrow measure of cost causation as it does not consider all of the planning and operating considerations that influence the type of investments made, in particular the objective of achieving low-cost energy. For utilities that have made significant investments in higher capital cost baseload generation, this allocator disregards the primary driver of these investments which is to provide lower cost energy throughout the year.
- Reliance on a single peak demand results in an allocation factor with high variability from year to year, which can have a significant impact on annual revenue requirements and jurisdictional earnings.
- Because it is difficult to forecast the month and magnitude of the system peak demand, the 1CP does not lend itself well to ratemaking based on forecasts.

2. Three Month Coincident Peak Demand (3CP)

Positive Aspects

- Like the 1CP, the 3CP method is a simple calculation (uses the top three peak demand hours during the year) and has an intuitive basis, i.e., that generating and transmission assets are secured to meet the highest demand season of the year.
- By incorporating the three highest demand months, this measure takes more of a seasonal approach to determining contributions to system peak, which mitigates some volatility of 1CP.
- The 3CP method may be the most suitable in systems where the annual system peak demand can occur in any month of the peak season.

Areas of Concern

- Even though three months are used, the 3CP is a narrow measure of cost causation as it does not consider all of the planning and operating considerations that influence the type of investments made, in particular the objective of achieving low-cost energy.

- Reliance on only three peak demands results in a variable allocation factor which can significantly impact annual jurisdictional revenue requirements.

3. Four Month Coincident Peak Demand (4CP)

Positive Aspects

- The 4CP is a minor improvement to the 3CP as it reflects a broader seasonal approach to determining contributions to system peak and mitigating factor variability.
- Like the 1CP and 3CP, this method has the intuitive foundation that generating and transmission assets are secured to meet the high demand season.

Areas of Concern

- The 4CP is not fully reflective of cost causation as it does not consider planning and operating considerations (other than meeting peak demands) that influence the type of investments made, such as achieving low-cost energy.
- Reliance on only four peak demands results in a more volatile allocator than one based on 12CP, which can impact annual jurisdictional revenue requirements.

4. Summer/Winter Coincident Peak Demand (SWCP)

Positive Aspects

- This method reflects jurisdictional contributions to both the summer and winter season system peaks which is meaningful for multi-state utilities in northern climates.
- Use of six monthly peaks improves stability of the allocation factor over other demand-only methods such as the 1CP, 3CP, and 4CP.

Areas of Concern

- Like other demand-based allocators, this method does not adequately consider all of the planning and operating factors driving investments, most notably the installation of baseload facilities to produce low-cost energy year round.

5. 12 Month Coincident Peak Demand (12CP)

Positive Aspects

- The 12CP method reflects jurisdictional contributions to system peaks throughout the year.

- Use of the twelve monthly peaks improves stability of the allocation factor over other demand-only methods discussed previously.
- Twelve data points could be an adequate proxy for the influence that energy use (as opposed to coincident peak demands) has on a system's design and cost.

Areas of Concern

- As a demand-based method, this method does not specifically seek to capture the importance of facilities intended to produce low-cost energy year-round. However, as noted above, in practice this seems to have minimal impact on the results.

6. Weighted 12 Month Coincident Peak Demand (W12CP)

Positive Aspects

- The weighted 12CP method reflects jurisdictional contributions to system peaks throughout the year, like the 12CP method.
- Use of twelve monthly peaks improves stability of the allocation factor over other demand-only methods discussed previously.
- Using twelve data points will partially proxy the influence that energy use has on the design and costs of the system.

Areas of Concern

- The W12CP method places more weight back on the highest peak demands of the year, eroding some of the value of using many demand hours to reflect the impact of energy use.
- The choice of weights seems arbitrary.
- Weighting each monthly demand beyond is not a calculation commonly understood or used.

7. 36 Month Coincident Peak Demand (36CP)

Positive Aspects

- Like the 12CP, the 36CP method reflects contributions to system peaks throughout the year.
- Use of thirty-six monthly peaks increases the stability of the allocation factor over other demand-only methods.
- Thirty-six data points provide a good proxy for the influence that energy use (as opposed to peak demands) has on the design and costs of the system.

Areas of Concern

- Use of the 36 months gives rise to the issue of whether the data should be historical, present, or future oriented, or a combination of these time periods. This introduces complexity and perhaps adjustments due to the timing of rate cases or annual earnings reports.
- As a demand-based method, this method does not specifically seek to capture the importance of facilities intended to produce low-cost energy year-round.
- This method may not readily reflect more recent changes in jurisdictional load profiles.

8. Equivalent Peaker Using Single Peak Demand (EQ1CP)

Positive Aspects

- The EQ1CP method directly recognizes the importance of both capacity and energy considerations in planning and building generation and transmission infrastructure. Stratifying generation assets into investments for meeting peak demands and those to produce low-cost energy allows the allocation of costs based on both peak demand and energy loads from the various jurisdictions.

Areas of Concern

- While the theory behind it has an intuitive quality, the actual stratification process is more complicated and time-intensive. It is generally not updated outside of rate proceedings. Use of a single peak demand to allocate capacity-related costs has some of the same negative qualities discussed in relation to 1CP above (volatility, forecastability).

9. Equivalent Peaker Using 4 Month Peak Demands (EQ4CP)

Positive Aspects

- The EQ4CP method directly recognizes the importance of both capacity and energy considerations in planning and building generation and transmission infrastructure. Stratifying generation assets into investments made to meet peak demands and those made to produce low-cost energy allows the allocation of costs based on both peak demand and energy loads from the various jurisdictions.
- Use of a 4 month season to allocate capacity costs improves the annual stability of the allocator while maintaining focus on the peak.

Areas of Concern

- While the theory behind it has an intuitive quality, the actual stratification process is complicated and time-intensive. It is generally not updated outside rate proceedings.

10. Equivalent Peaker Using 12 Month Peak Demand (EQ12CP)

Positive Aspects

- The EQ12CP method directly recognizes the importance of both capacity and energy considerations in planning and building generation and transmission infrastructure. Stratifying generation assets into investments made to meet peak demands and those made to produce low-cost energy allows the allocation of costs based on both peak demand and energy loads from the various jurisdictions.
- Use of all 12 months to allocate capacity costs improves the annual stability of the allocator.

Areas of Concern

- While the theory behind it has an intuitive quality, the actual stratification process is complicated and time-intensive. It is generally not updated outside of rate proceedings.
- Use of all 12 monthly demands to allocate the capacity portion of system investment only may introduce more energy influence than is appropriate given that an energy allocator is already used to allocate a large portion of costs.

11. Average and Excess Demands (AED)

Positive Aspects

- Recognizes that energy plays a role in the planning and building of system generation and transmission.
- Does not require stratification of the generation fleet as it assumes that the system load factor is a good proxy of the portion of costs that should be allocated based on energy (or, average demand).

Areas of Concern

- This method is rather difficult to understand and explain. Concepts like "load factor" and "non-coincident peaks" are part of the calculation, and is difficult to understand why load factor forms the basis for determining what costs are energy based.
- This method can produce results that are quite variable and difficult to forecast.

12. Peak and Average Demand using 1CP (PkAv1CP)

Positive Aspects

- Recognizes that energy plays a role in planning and building of system generation and transmission.
- Does not require stratification of the generation fleet; uses a ratio of average demand to the sum of average demand and coincident peak demand as a proxy of the portion of costs that should be allocated based on energy (or, average demand).

Areas of Concern

- Like the AED method, this method is rather difficult to understand. The weighting of average demand ratios with coincident peak ratios to determine the energy and capacity portions is not linked with the utility's generation profile.
- This method can produce results that are quite variable and difficult to forecast.

IV. Assessment

For each of the methods evaluated, allocation factor results and comparisons of the results across time and by methods are provided in the Appendix. Specifically, Appendix A shows the allocation factor produced by each method for the years 2005 through 2013. In each case, the allocation factor is calculated using actual, weather-normalized actual, and budget data, with each separately graphed to show variances both between budget and actual results as well as some indication of weather sensitivity. Appendix B provides a comparison of the allocation factor resulting from each method as applied to NSPM's North Dakota jurisdiction actual historic data on a year by year basis for the period 2004 through 2013. Appendix C tabulates the allocations factors for all methods as calculated with actual, weather normalize actual, and budget data across the time period.

To assess the selected allocation methods, a set of criteria was developed based on requirements in the Settlement Agreement as well as key attributes of well-designed allocators. The allocators were judged on the following criteria:

1. *Representative of Costs* – How well does the method reflect the load profiles of 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 costs in conjunction with methods approved in its other state jurisdictions?

These criteria are consistent with a three-part test that has been considered by the North Dakota Commission in prior Company rate cases: 1) Does it reasonably reflect the incremental cost caused by each jurisdiction? 2) Is it consistently applied among each of the Company's jurisdictions? 3) Is it understandable and easy to administer?

In addition to testing the allocators in the context of these criteria, this study also quantified the revenue requirement impacts in North Dakota of changing the jurisdictional allocation method from the current 12CP method.

A. Cost Representation

A key principle to consider in the assignment of system costs to state jurisdictions is whether the method allocated the costs in a manner that is representative of how the costs are caused. This principle is important because it helps to assure both fairness and economic efficiency in ratemaking.

The NARUC Cost Allocation Manual States, "Cost causation attempts to determine what influences a utility's production plant investment decisions. Cost causation considers: 1) that utilities add capacity to meet critical system planning reliability criteria such as loss of load probability, loss of load hours, reserve margin, or expected unserved energy; and 2) that the utility's energy load or load duration curve is a major indicator of the type of plant needed. The type of plant installed determines the cost of the additional capacity. This approach is well represented among the energy weighting methods of cost allocation."[10]

It is commonly understood that, presently, the least expensive generation option for adding capacity is to build combustion turbines to serve as peaking plants. Yet, most utilities also plan for and build intermediate and baseload plants—even at a much higher capital cost per MW than a peaking unit—in order to meet the additional energy loads they must serve most cost-effectively. Utility planners understand that baseload plants are more expensive to build, but that their fuel costs are relatively low and they are designed to run at high load factor. This means they can produce low-cost energy throughout the year in addition to supplying needed capacity.

As explained by Mr. Steve Wishart in Xcel Energy's most recent rate case, Xcel Energy makes its resource investments within a long-term planning horizon—30 years or more for generation facilities and 20 years or more for power purchase agreements.[11] Many utilities, including Xcel Energy, do not make these resource selection decisions based only on meeting peak load, but rather how to meet all loads throughout the planning horizon on a reliable and cost-effective

[10] P. 38, NARUC Electric Utility Cost Allocation Manual, January, 1992.

[11] See Rebuttal Testimony of Steve Wishart in Case No. PU-12-813 at 12.

basis. The fixed costs of intermediate and baseload production plants are above what is required simply to meet peak load, but result in lower energy costs to serve energy needs overall.

In addition, because utilities must plan their system operations to meet loads in all months of the year, it is important to consider overall reserve margin throughout the year and any jurisdiction's load contributions to that reserve margin. Thus, scheduled maintenance also becomes a relevant factor in determining the appropriate jurisdictional allocator. One jurisdiction's contribution to the system peaks in months when the system peak is not particularly high can also be important if reserve margins are low in that month, for example, because system reserve margin has been reduced due to scheduled maintenance. This is also a factor in determining how much of the system costs should be allocated to that jurisdiction and which allocation method best reflects cost causation.[12]

The primary emphasis of our analysis was on the non-fuel generation costs which comprise about 40-45 percent of annual revenue requirements, rather than transmission costs which comprise about 10 percent of revenue requirements. It is worth noting that, like generation, not all transmission investment across an integrated system is made to meet overall system peak demand. There are pockets of congestion and other local load considerations that lend support to the use of methods that incorporate data points other than a single or seasonally-based system peak demand. MISO, the regional transmission organization (RTO), of which NSPM is a member, uses the 12CP method as the basis for its transmission system billings.

The table below summarizes our general conclusions regarding cost representativeness of the various cost allocation methods.

TABLE 5: ASSESSMENT OF COST REPRESENTATION

Method	Observations
1CP	The impacts of energy on generation and transmission investment choices are ignored, and the use of only a single peak demand for the year may be overly narrow and unrepresentative of how a system is planned or operated.
3CP	The primary focus is on jurisdictional contributions to peak demand, even though it takes a seasonal approach; planners do not only consider peak demands when making system investment decisions.
4CP	As with 1CP and 3CP, the primary focus is on jurisdictional contributions to peak demand; arguably, planners do not typically consider only peak demands when making system investment decisions.
12CP	The length of time over which peaks are averaged creates a "proxy" for energy use.
36CP	Using three times as many months as the 12CP provides better proxy for energy use.
SWCP	Adding a winter peak may improve a the representativeness of the allocation

12 See Rebuttal Testimony of Scott Brockett in Case No. PU-12-813 at 10-12.

	than using only 1CP, 3CP, or 4CP; however the use of only 2 seasonal peaks still ignores impacts of other six months of the year if they affect the utility's investment decisions.
W12CP	Places more emphasis on the system peak demands in a somewhat arbitrary manner, but using multiple months provides some representation of energy use.
EQ1CP	Stratification of costs to capacity and energy mimics typical utility planning and investment; reliance on a single peak demand hour to allocate capacity costs may be less representative of overall costs.
EQ4CP	Stratification of costs to capacity and energy mimics typical utility planning and investment; use of four monthly (seasonal) demands to define the system peak and allocate stratified capacity costs may improve representativeness over EQ1CP.
EP12CP	Using 12 months of coincident demands adds more energy-based allocation to a method that already allocates significant investment-related costs with energy.
PkAv1CP	Uses average demand (which is equal to energy consumption), but may assign a larger percentage (typically 60%-70%) of production costs to the "capacity" category than either the Eq Peaker or Avg & Excess methods.
AED	Uses a simple stratification approach (where system load factor defines the energy portion) and employs the concept of jurisdictional "excess demand" to allocate the remaining 40%-50% of production defined as capacity-related.

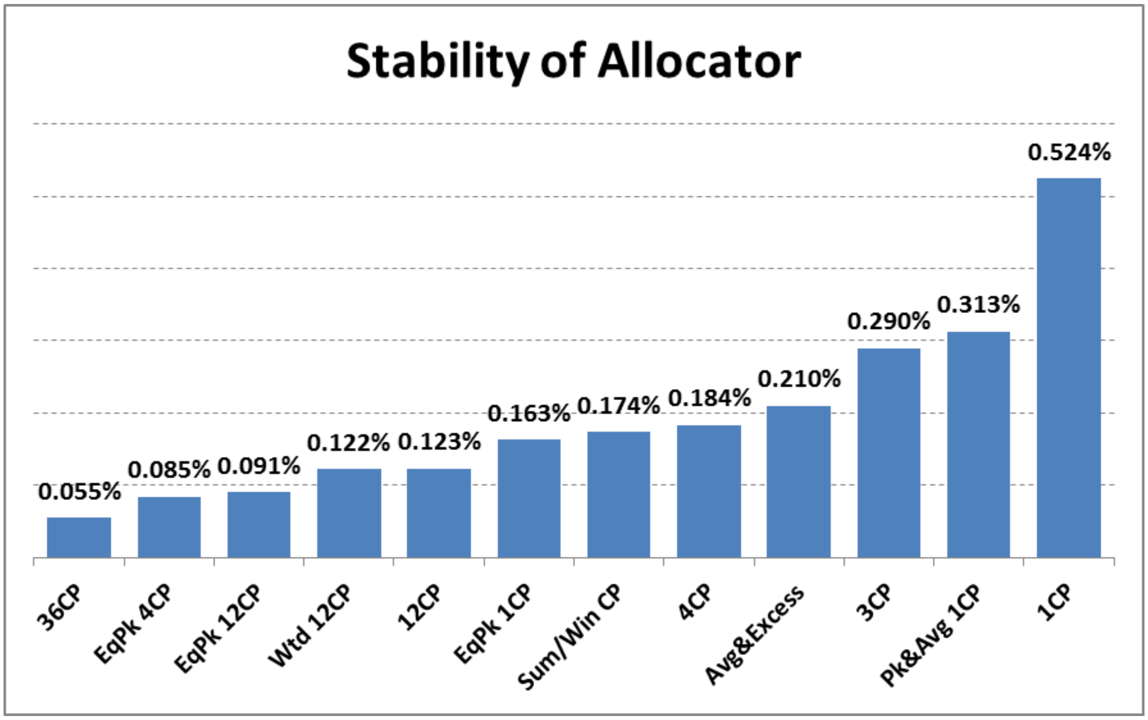
Although there are no empirical approaches for ranking the methods for accuracy of cost representation, the methods which approximate that of the resource planner may have greatest appeal. In that regards the equivalent peaker methods using 1CP and 4CP, that is, EQ1CP and EQ4CP, methods likely come closest. Of note, based on our empirical analysis of the past ten years of NSPM data, the 12CP and 36CP approximate the numerical results of the the EQ1CP and EQ4CP methods for North Dakota.

B. STABILITY OF ALLOCATION FACTOR

It is preferable that the allocation factors produced by a given method not fluctuate significantly from year to year. A highly fluctuating allocator would significantly affect a utility's jurisdictional regulated earnings up and down as these system allocators typically impact the majority of a utility's annual investment-related expenses. High earnings volatility would make it more difficult for regulators to determine if fiscal year earnings either above or below the authorized levels were an anomaly or indicative of a system revenue/cost imbalance. It may require more complete or detailed reporting of weather-normalized results by Xcel Energy to communicate better the reasons for changes in earnings, assuming that some of the volatility would be due to a method's reliance on one or a few data points. Lastly, it may send an inaccurate signal to the utility about the necessity for a future rate application.

In this study, we assessed the factor stability of each allocation by first calculating the allocation factor for each of the various methods over a 10 year period using historical Company demand and energy data. We then developed a linear "best fit" trend line for each method's historical results using the least squares method. This trend line would represent the straight line that most closely fits the historical pattern of factors. A statistical calculation called "Root Mean Square Error"[13] (RMSE) was then performed for each method to measure how far the actual allocation factors calculated for each year deviated from the method's "best-fit" trend line. In other words, we measured how closely "clumped" the 10 years of results were around the trend line for each method. A low number would indicate very little deviation from the trend line—a "homogenous" trend—and thus a more stable allocator. Figure 1 below ranks the RMSE scores for each method.

FIGURE 1



As shown by the chart, the Equivalent Peaker and multiple-month coincident peak methods (i.e., at least 12 months) generated the most stable factors of the methods tested. This outcome is expected in that the more data points that are used to generate the factor, the lower the chance that the anomalous data can impact the results.

C. PREDICTABILITY OF ALLOCATOR

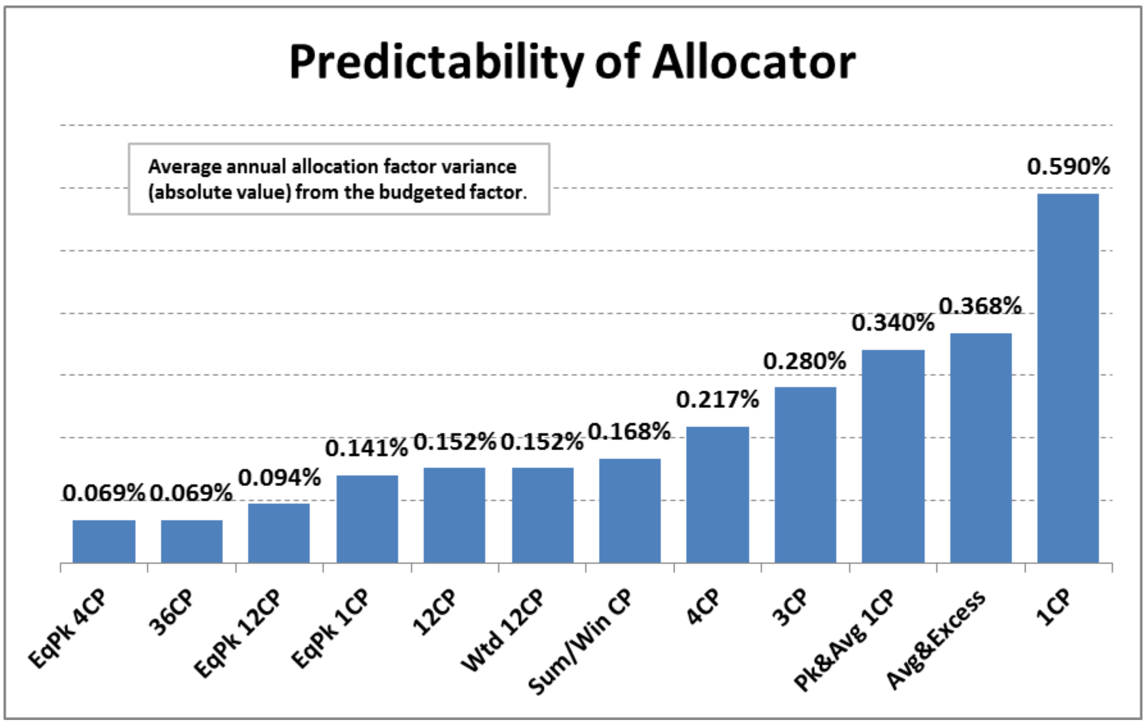
Rate stability is often a regulatory policy goal and has been stated as a goal by this Commission. In that context, given the significant impact that the jurisdictional allocator has on the overall cost of service and, ultimately, rates, it is important that a utility be able to forecast with reasonable accuracy what the allocation method factor will be for a given test year for the purpose of estimating the jurisdictional revenue requirement. For many of the same reasons that

[13] If each method's 10 year history were plotted together with a line of best fit, the variance, or residual, for each data point is the vertical distance between the point and the line. Each of these residuals is squared, and the RMSE shown in Chart 1 is the square root of the average squared.

certain allocation factors will fluctuate from year to year (i.e., dependence on a single or few hours of peak demand data, changes in the jurisdictional load profile characteristics, exposure to variances in weather, etc.) there is also difficulty in the art of predicting what the actual allocation factor will be when assembling either a historical or a future test year for setting rates. Not only can this lead to under- or overstated rates, but it can also make it difficult to ascertain whether a utility is achieving its authorized return on equity.

To test predictability, we compared allocation factors calculated from actual historical data for the 10 year period from 2004 through 2013 to the equivalent allocation factors calculated using forecasted during the budget cycle previous to each year. Figure 2 below shows the average annual difference (in absolute value terms) for each method. Again, low numbers indicate a high ability to forecast accurately.

FIGURE 2



We can see from the chart that again the Equivalent Peak and multiple month coincident peak methods were the easiest to forecast in this group.

D. SIMPLICITY/UNDERSTANDABILITY

Other things equal, we would recommend a simpler and more understandable allocator over one that is complicated. A complicated allocator is more difficult to explain to interested audiences and may be more difficult to audit or replicate. An allocator that depends on data that is not normally filed in rate cases could add to the complexity of the task facing interveners and the Commission. The general design of the allocator should make sense, the inputs should be reasonably easy to acquire and audit, and the computation of the allocation factor should be relatively easy to follow and understand.

Table 6: Assessment of Allocation Method Simplicity/Understandability

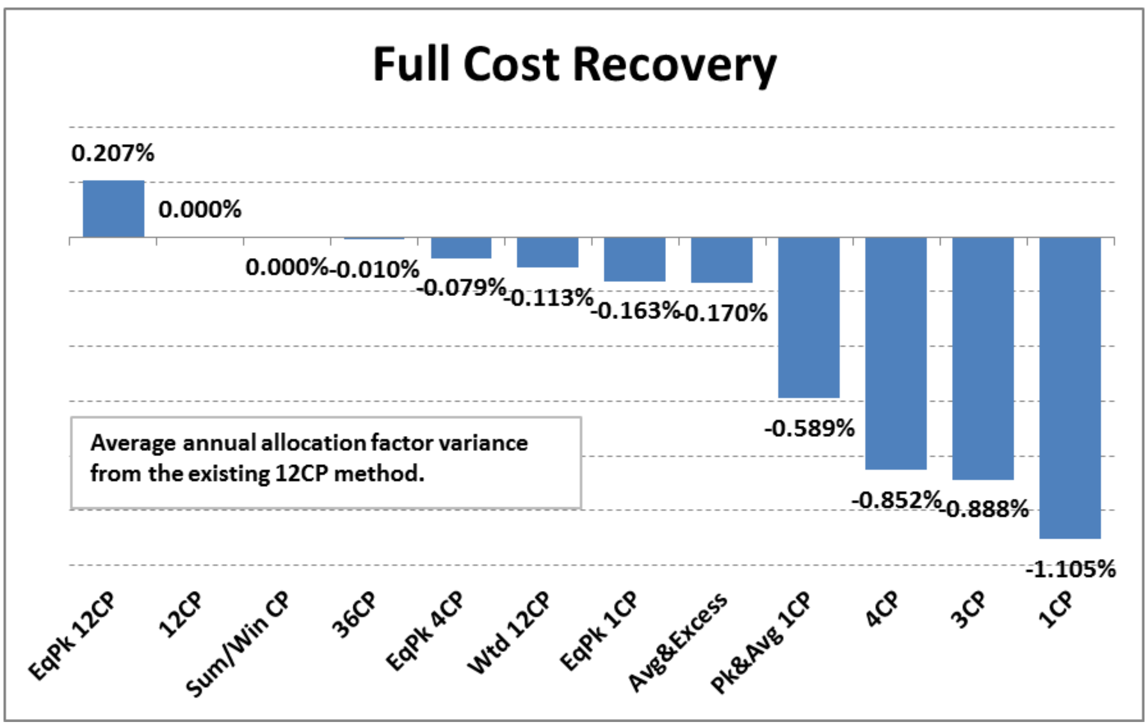
Method	Observations
1CP	Requires data on system and coincident peaks for one month and uses a simple calculation. Minimally data intensive.
3CP	Requires system, coincident peak demand information from only three months, once those highest months are identified. Same basic calculation as 1CP.
4CP	Requires system, coincident peak demand information from only four months, once those highest months are identified. Same basic calculation as 1CP, 3CP.
12CP	Requires system, coincident peak demand information for each month of the year. No need to search for high demand months. Same basic calculation as 1CP, 3CP, and 4CP methods.
36CP	Requires system, coincident peak demand information from each month of three consecutive years. No need to search for high demand months, but inputs may need to be a combination of actual and forecasted data. Same basic calculation as other multi-month CP methods.
SWCP	Requires identifying system, coincident peak demands for each month of both the defined summer season and winter season. Once done, uses same computation as other CP methods.
W12CP	Each year the lowest system peak demand month must be identified for purposes of weighting each monthly demand. While adding weight to high demand months is intuitive, there is no clear basis for this specific weighting technique.
EQ1CP	Stratification of generation costs to capacity and energy has an intuitive basis. However, the stratification process is rather complex, requires several steps to complete, and requires very specific costing information for each plant on the system that is not generally made available in rate cases.
EQ4CP	Same as the EQ1CP, except that additional monthly demands are included for the capacity-related costs.
EP12CP	Same as the EQ1CP and EQ4CP methods, except that all 12 months demands are included for the capacity-related costs.
PkAv1CP	The 1CP and energy allocators are weighted based on an average demands vs. coincident peak demands. This is a mathematical exercise that is not very intuitive.
AED	The quasi-stratification method uses system Load Factor to determine what costs are energy-based, and also uses the less intuitive concept of “excess demand” and introduced non-coincident peaks into calculation.

E. System Cost Recoverability

Another important criterion for evaluating the various methods is how well the method affords the utility an opportunity to recover its full system costs given that the 12CP is the approved method in South Dakota and Minnesota. Since the early 1990's NSPM has historically calculated its jurisdictional allocations of system costs using the 12CP method in each of the three states it serves (North Dakota, South Dakota, Minnesota). Using a common method in all three jurisdictions gives Xcel Energy an opportunity to recover 100 percent of its approved system costs. If North Dakota or any other of the three states were to switch to a different allocator other than the 12CP method, then the assigned system costs across the three jurisdictions will likely not amount to 100 percent of the system total.

To assess how well the various allocation methods would afford Xcel Energy an opportunity to recover all allowed system costs if adopted in North Dakota, we again used 10 years of historical data and compared the allocation factors of the studied methods to the allocation factor produced by the 12CP method currently approved in North Dakota. Figure 3 below shows the average difference of each method from the 12CP method during the ten year span (a positive variance showing recovery is greater than the 12CP, and a negative variance showing recovery to be lower). Only one method in the entire group – the Equivalent Peaker using 12CP – yielded on average a higher allocator (and higher North Dakota revenue requirement) during the 2004-2013 period than the 12CP. The SWCP would appear to be the other method that would allow Xcel Energy an opportunity to recover its approved system costs.

FIGURE 3



The detailed results can be found in Appendix C, Table C-1.

While the revenue requirement impact of each method on the Company's North Dakota operations was not a primary focus of our analysis, we note that based on estimates made in Xcel Energy's most recent North Dakota rate case (PU-12-813) and supported by this study, a 10 basis point (0.1 percent) change in the Company's jurisdictional production and transmission allocation corresponds to a $1.1 million to $1.5 million change in revenue requirements, depending on the method's application to both generation and transmission costs. Given this, a 1 percent change in the jurisdictional system allocator can impact NSPM's North Dakota test year revenue requirement by as much as $15 million

V. Conclusion

Cost allocators apportion the costs of investments historically undertaken by the utility and expenses currently incurred based upon the drivers of those costs, such as customer demand and energy use. 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 data 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 their contribution to monthly system peak demands averaged across all twelve months of the year.

In general, the EqP1CP and EqP4CP allocators provide sufficient recognition of both a jurisdiction's energy use and peak demand. They also take into account the overall generation fleet profile (eg, baseload, intermediate and peaking). Because 12CP and 36CP use data points from every month of the year, these methods also appear to proxy the impacts of energy on costs. We note that over the period we analyzed EqP4CP performs similarly to 12CP and 36CP. At the same time, the 12CP method requires far fewer calculations than the equivalent peaker methods, is relatively stable, and is the method predominantly used by utilities throughout the region.

We believe that our use of ten years of data is a reasonable time frame to have performed the analysis and represents an appropriate trade-off between contemporaneousness of data, which might suggest a shorter data series, and historical perspective, which would suggest a longer one. Further, the criteria that we have used for evaluating the allocators are reasonably comprehensive and are consistent with Commission criteria from previous rate dockets.

In our view, the adoption of the 12CP method in the NSPM states has been reasonable, and we do not find compelling reasons to recommend changing the method used by the Company in North Dakota.

VI. Appendices

Appendix A: Historical Allocation Trends (Budget, Actual, Weather Normalized)

The charts included in Appendix A show the calculated allocation factors in 2005 – 2013 for each of the 12 methods studied. Each chart includes a separate trend line for actual, weather-normalized actual, and budgeted factors determined from NSPM demand and energy data. The charts allow for the comparison of factors from year to year, indicate the trend (if any) over the 10 year period, show the variances between budgeted and actual results, and provide an indication of the method's sensitivity to weather extremes.

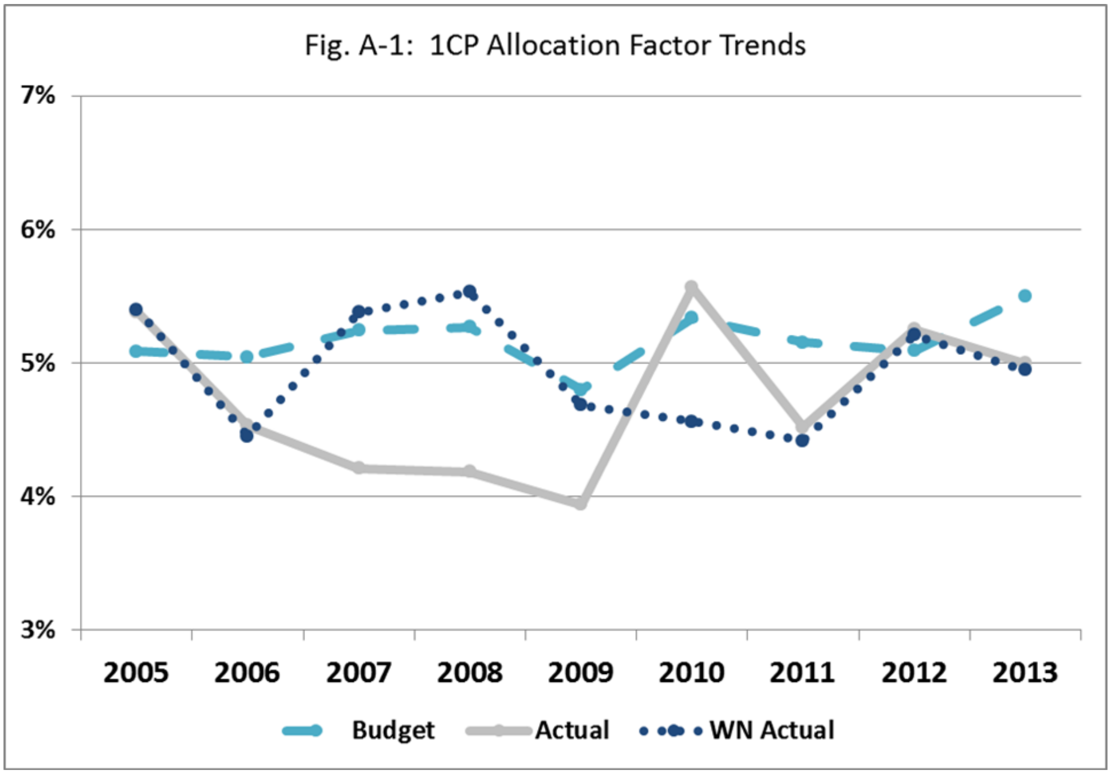


Fig. A-1: 1CP Allocation Factor Trends
7%
6%
5%
4%
3%
2005
2006
2007
2008
2009
2010
2011
2012
2013
Budget
Actual
WN Actual

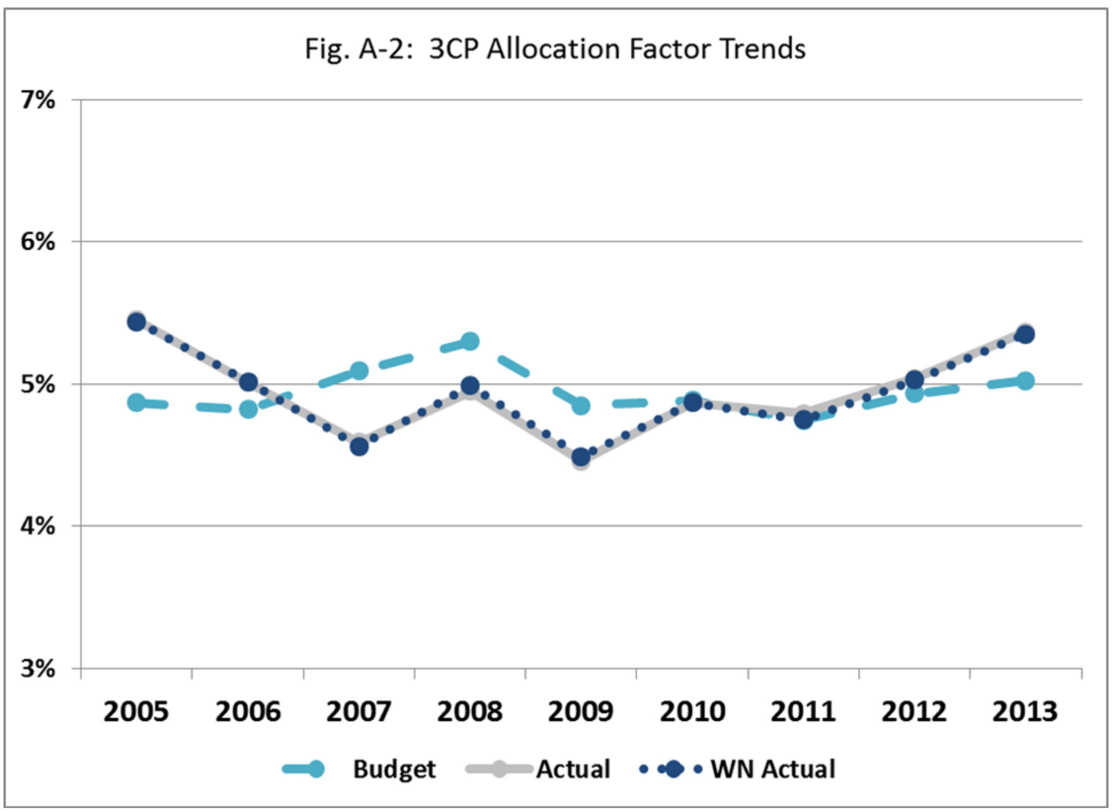


Fig. A-2: 3CP Allocation Factor Trends
7%
6%
5%
4%
3%
2005
2006
2007
2008
2009
2010
2011
2012
2013
Budget
Actual
WN Actual

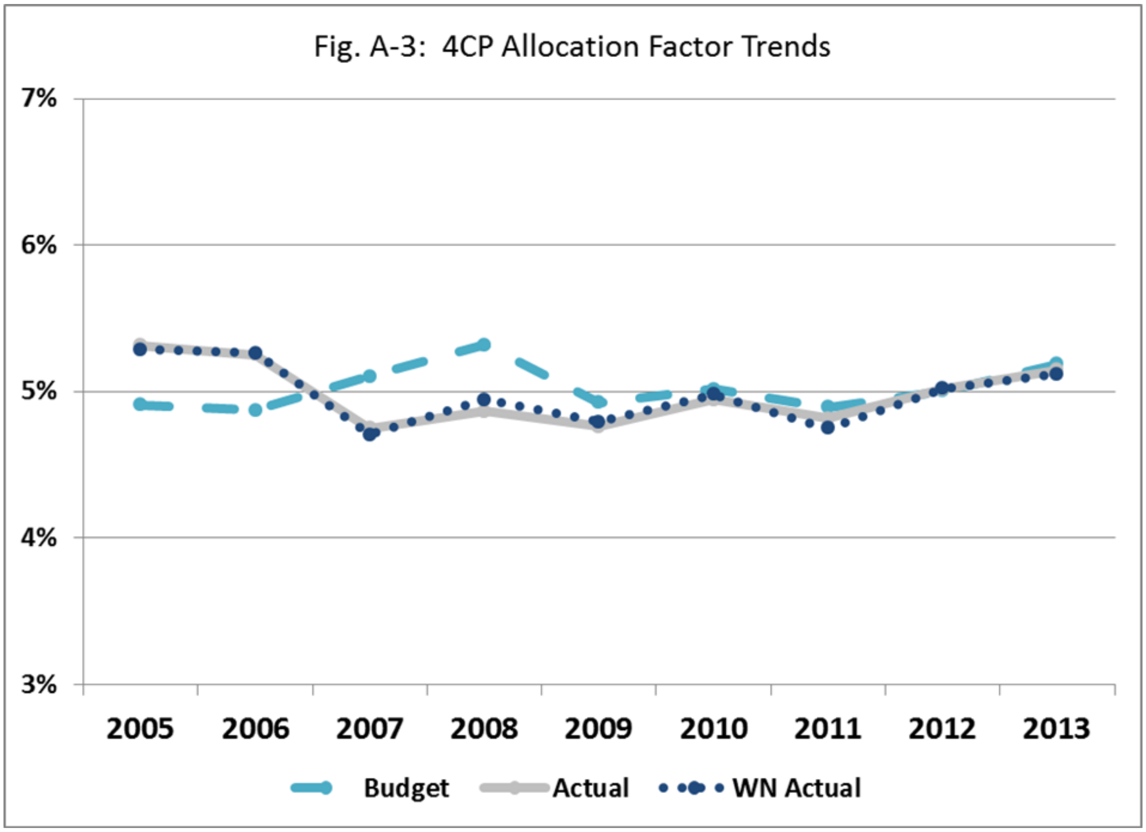


Fig. A-3: 4CP Allocation Factor Trends
7%
6%
5%
4%
3%
2005
2006
2007
2008
2009
2010
2011
2012
2013
Budget
Actual
WN Actual

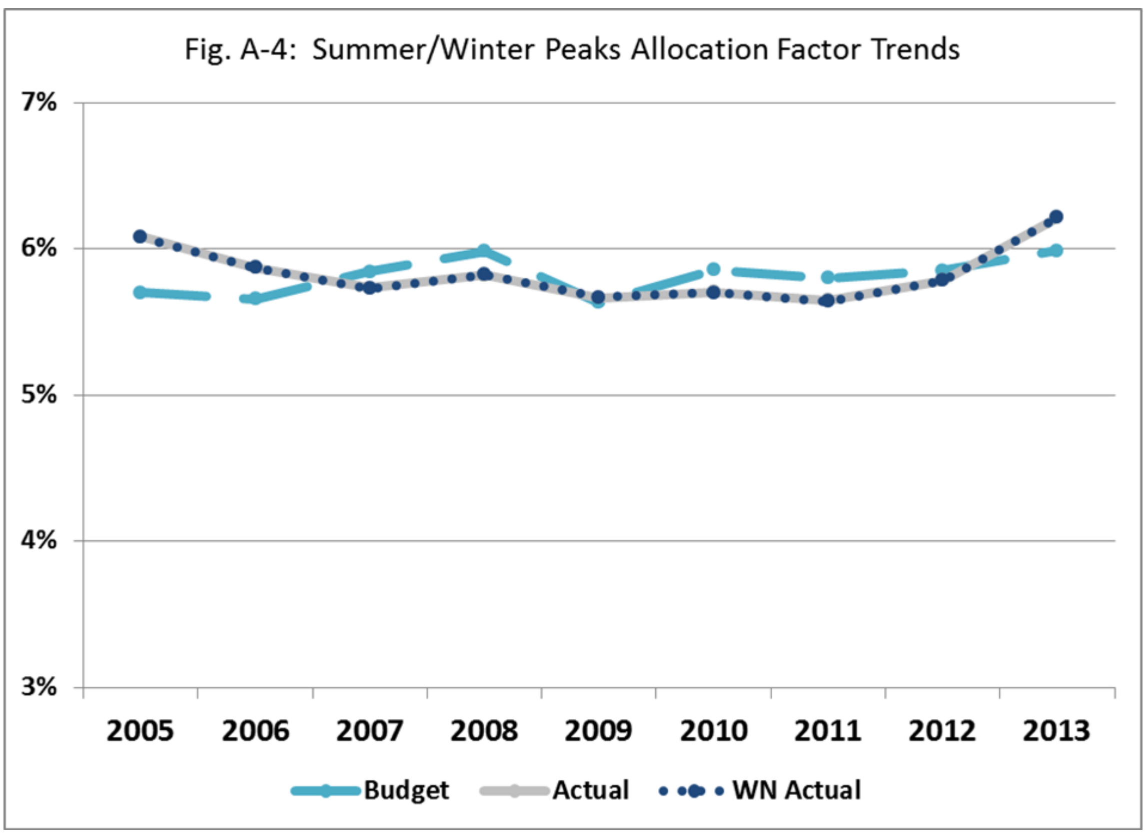


Fig. A-4: Summer/Winter Peaks Allocation Factor Trends
7%
6%
5%
4%
3%
2005
2006
2007
2008
2009
2010
2011
2012
2013
Budget
Actual
WN Actual

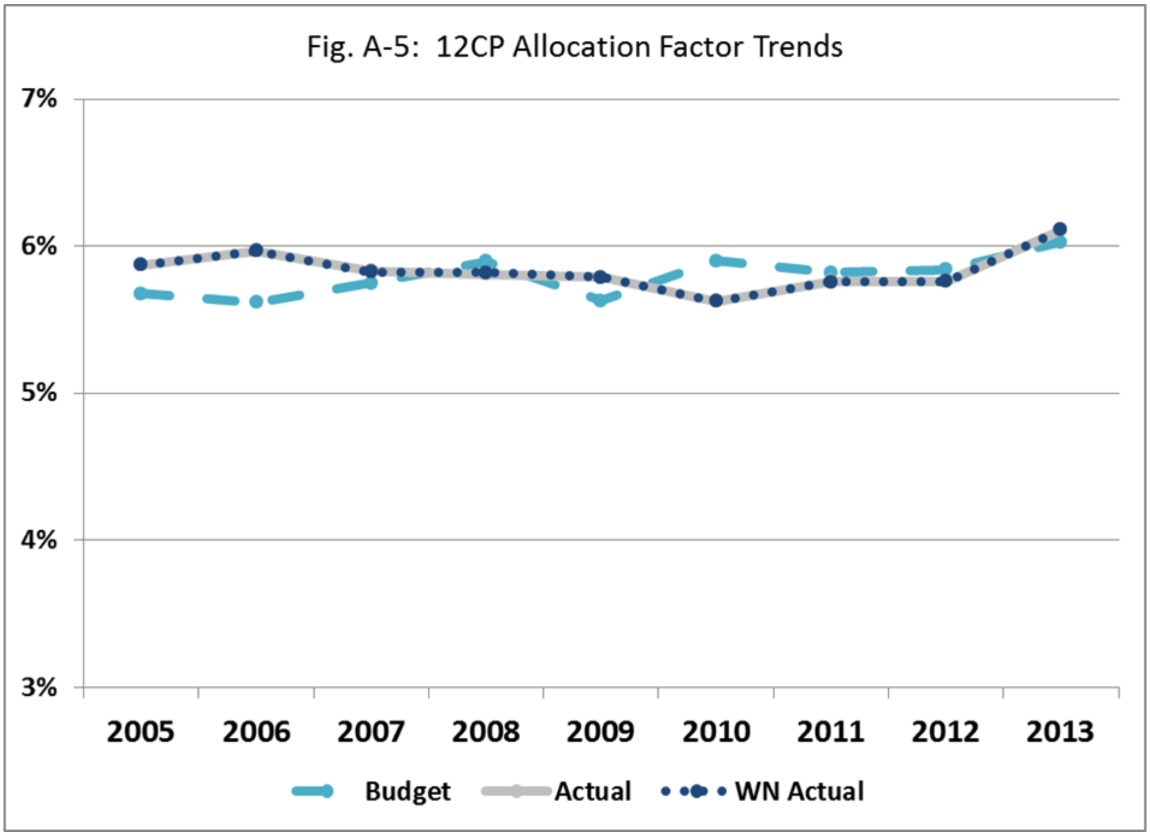


Fig. A-5: 12CP Allocation Factor Trends
7%
6%
5%
4%
3%
2005
2006
2007
2008
2009
2010
2011
2012
2013
Budget
Actual
WN Actual

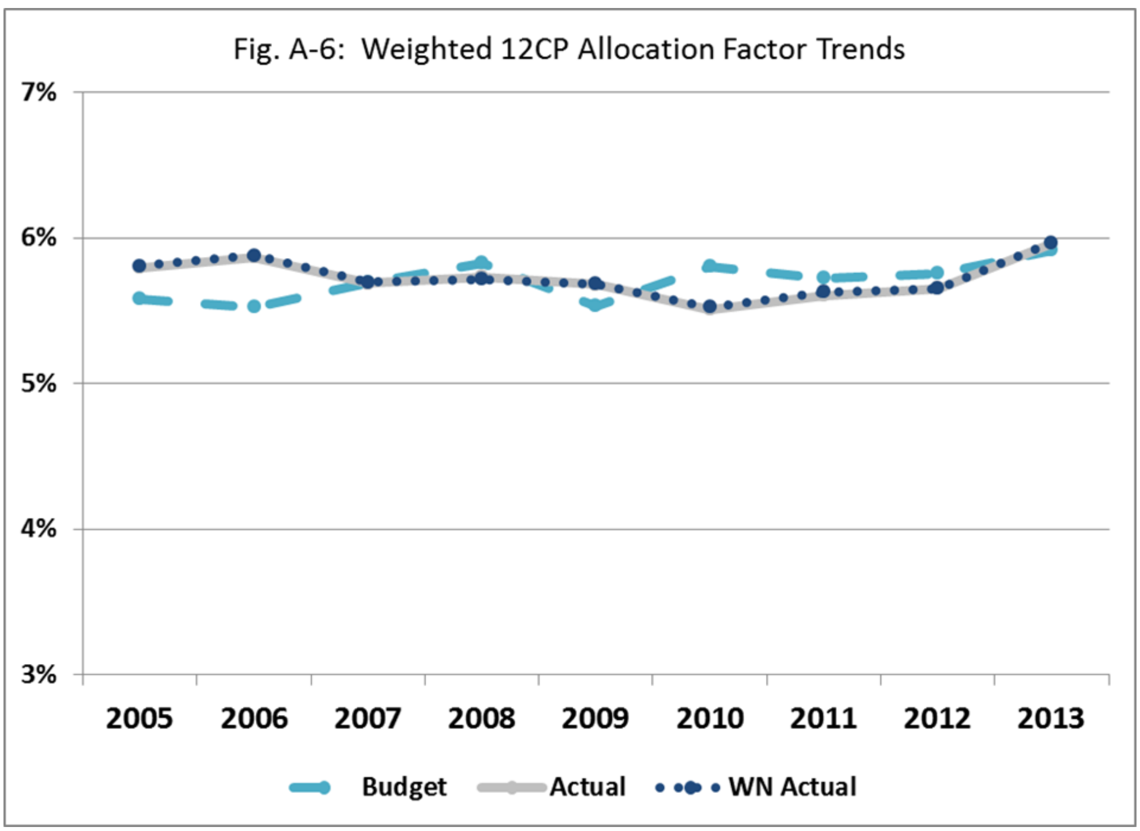


Fig. A-6: Weighted 12CP Allocation Factor Trends
7%
6%
5%
4%
3%
2005
2006
2007
2008
2009
2010
2011
2012
2013
Budget
Actual
WN Actual

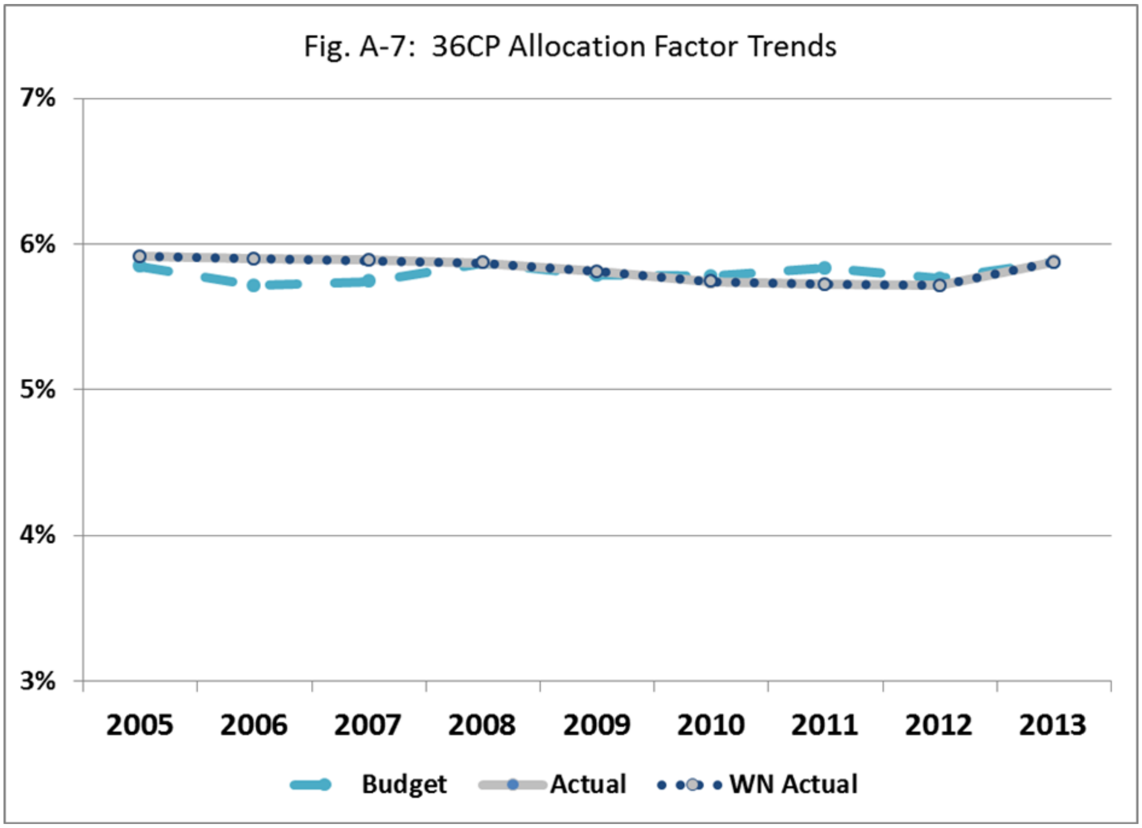


Fig. A-7: 36CP Allocation Factor Trends
7%
6%
5%
4%
3%
2005
2006
2007
2008
2009
2010
2011
2012
2013
Budget
Actual
WN Actual

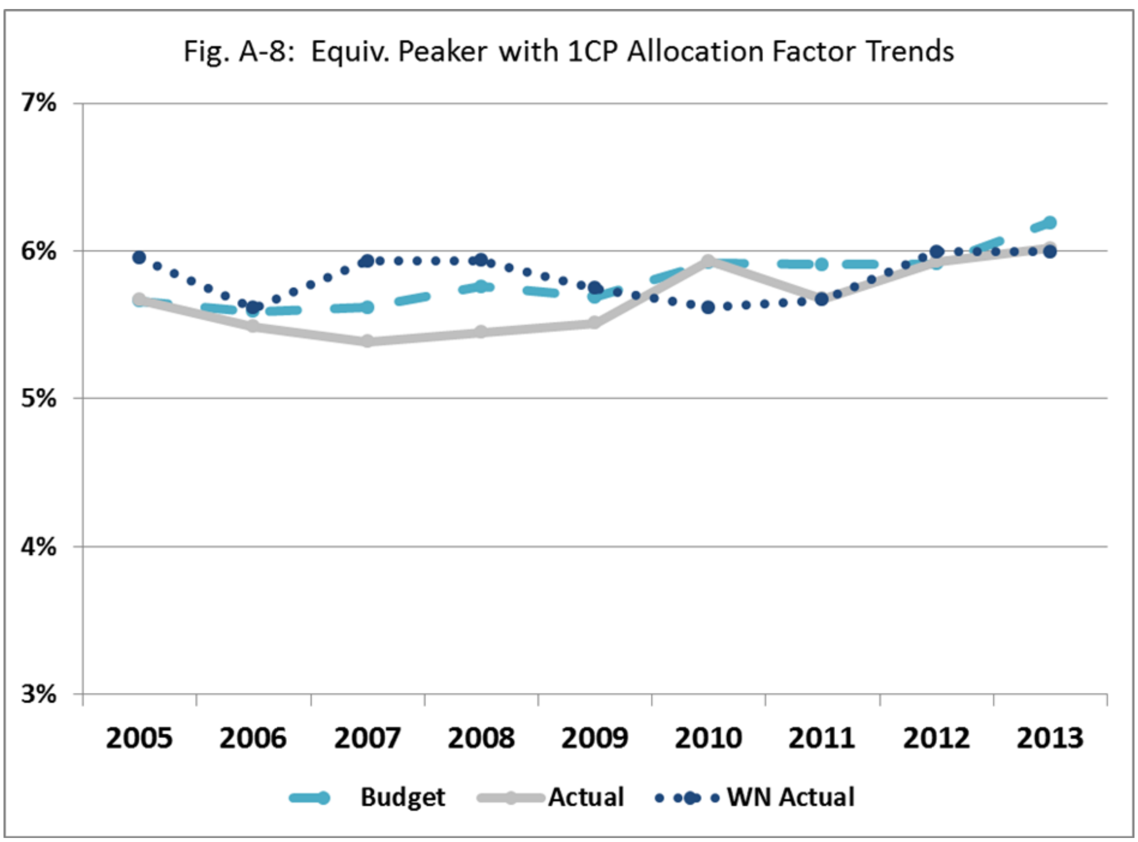


Fig. A-8: Equiv. Peaker with 1CP Allocation Factor Trends
7%
6%
5%
4%
3%
2005
2006
2007
2008
2009
2010
2011
2012
2013
Budget
Actual
WN Actual

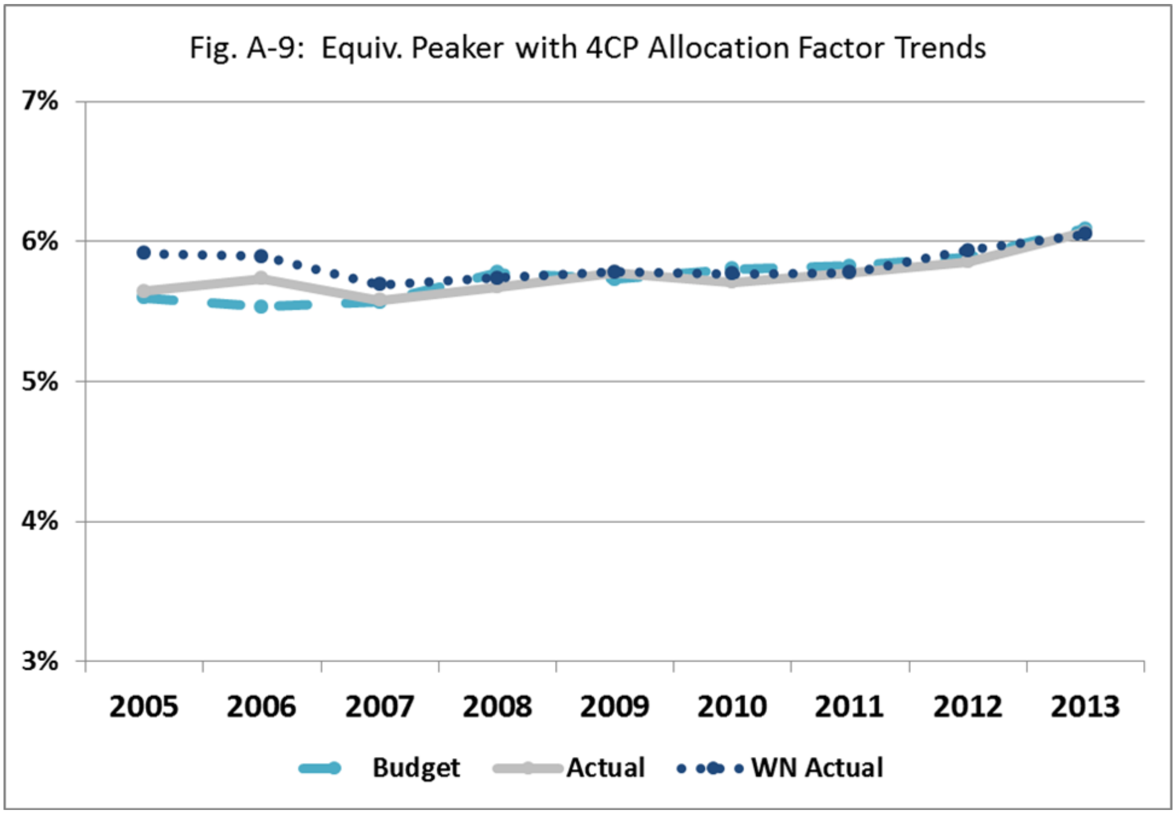


Fig. A-9: Equiv. Peaker with 4CP Allocation Factor Trends
7%
6%
5%
4%
3%
2005
2006
2007
2008
2009
2010
2011
2012
2013
Budget
Actual
WN Actual

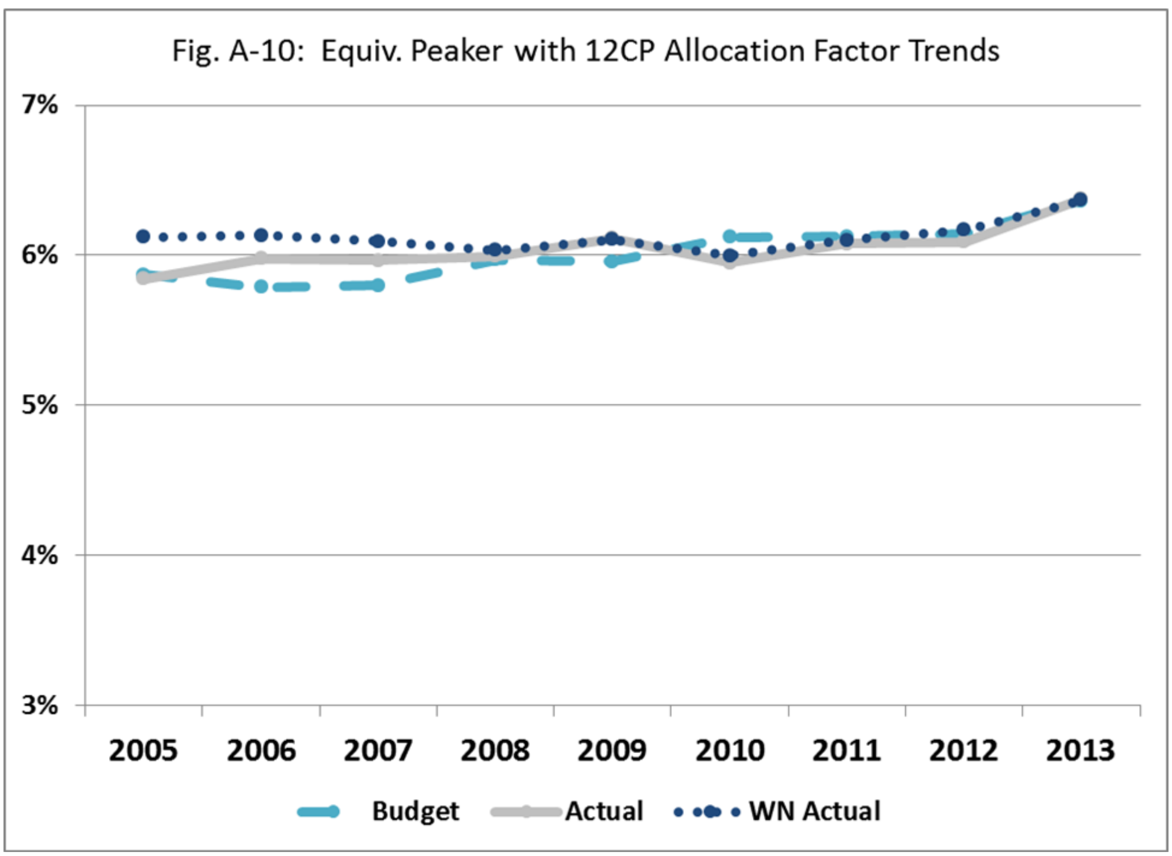


Fig. A-10: Equiv. Peaker with 12CP Allocation Factor Trends
7%
6%
5%
4%
3%
2005
2006
2007
2008
2009
2010
2011
2012
2013
Budget
Actual
WN Actual

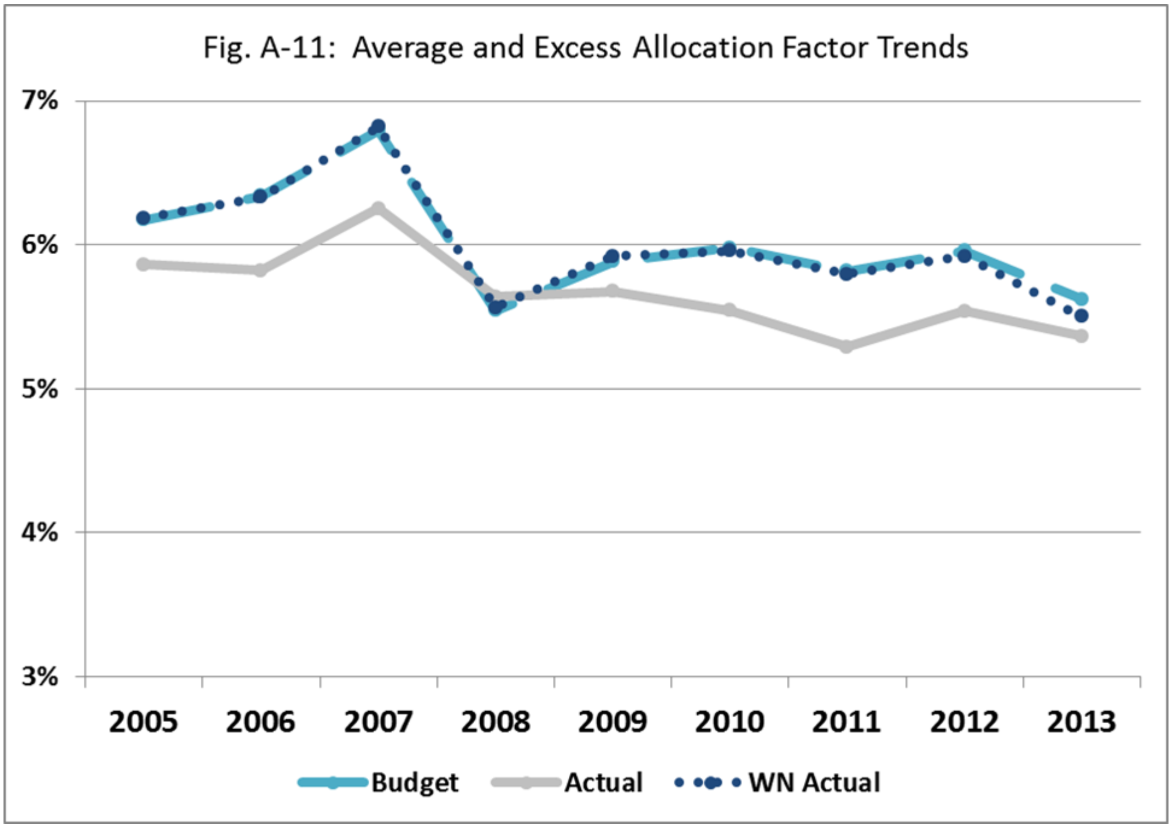


Fig. A-11: Average and Excess Allocation Factor Trends
7%
6%
5%
4%
3%
2005
2006
2007
2008
2009
2010
2011
2012
2013
Budget
Actual
WN Actual

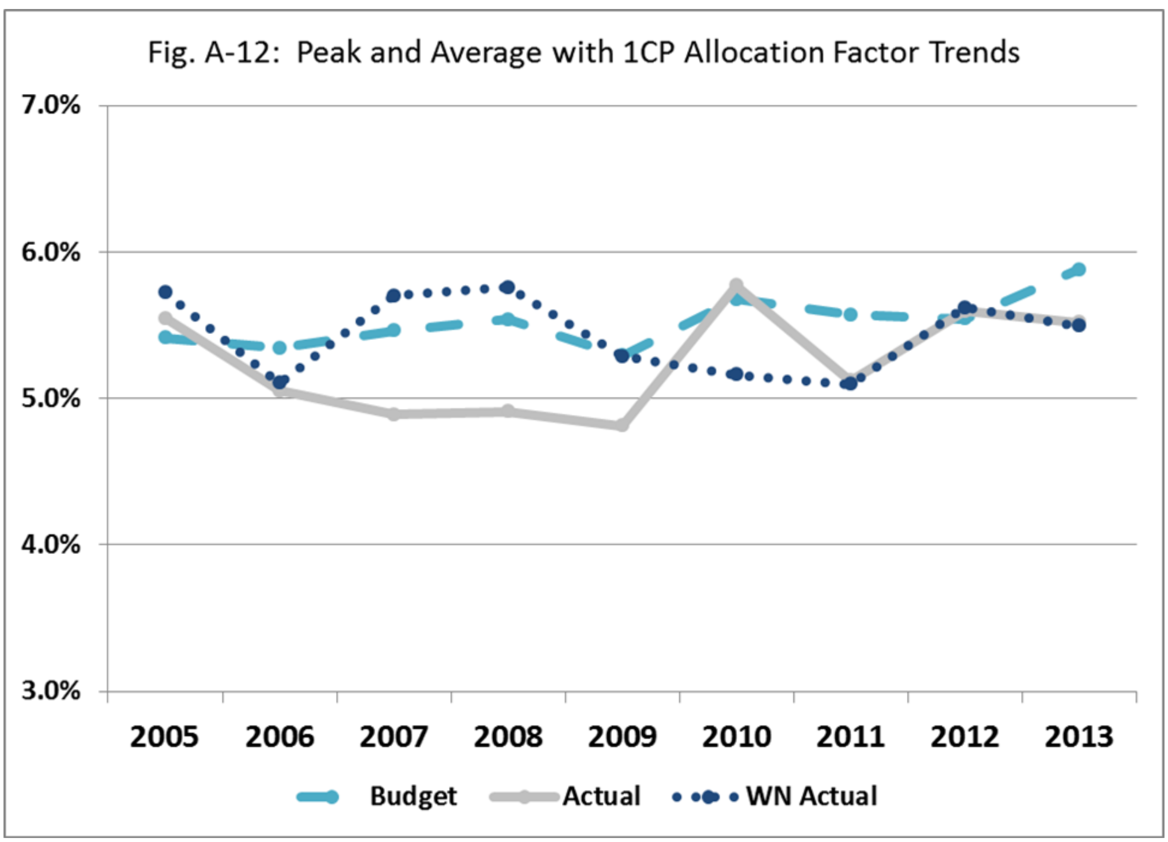


Fig. A-12: Peak and Average with 1CP Allocation Factor Trends
7.0%
6.0%
5.0%
4.0%
3.0%
2005
2006
2007
2008
2009
2010
2011
2012
2013
Budget
Actual
WN Actual

Appendix B: Year-by-Year Method Comparisons

The charts included in Appendix B show the allocation factors for all methods studied on a year-by-year basis (during the period 2004 – 2013). Each bar chart reflects all methods' allocation factors derived for a given year based on actual NSPM demand and energy data. The charts allow for the direct comparison of the factors determined by each and every method studied.

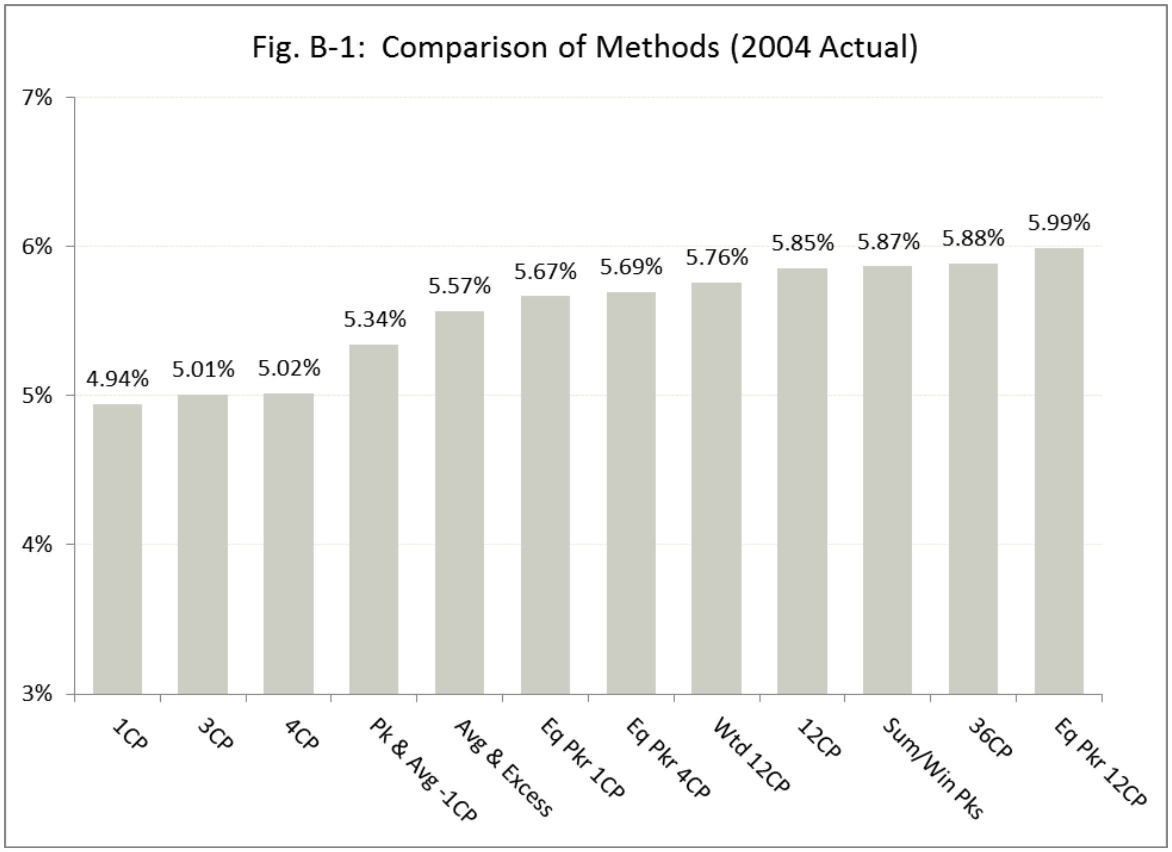


Fig. B-1: Comparison of Methods (2004 Actual)
7%
6%
5%
4%
3%
4.94%
5.01%
5.02%
5.34%
5.57%
5.67%
5.69%
5.76%
5.85%
5.87%
5.88%
5.99%
1CP
3CP
4CP
Pk & Avg -1CP
Avg & Excess
Eq Pkr 1CP
Eq Pkr 4CP
Wtd 12CP
12CP
Sum/Win Pks
36CP
Eq Pkr 12CP

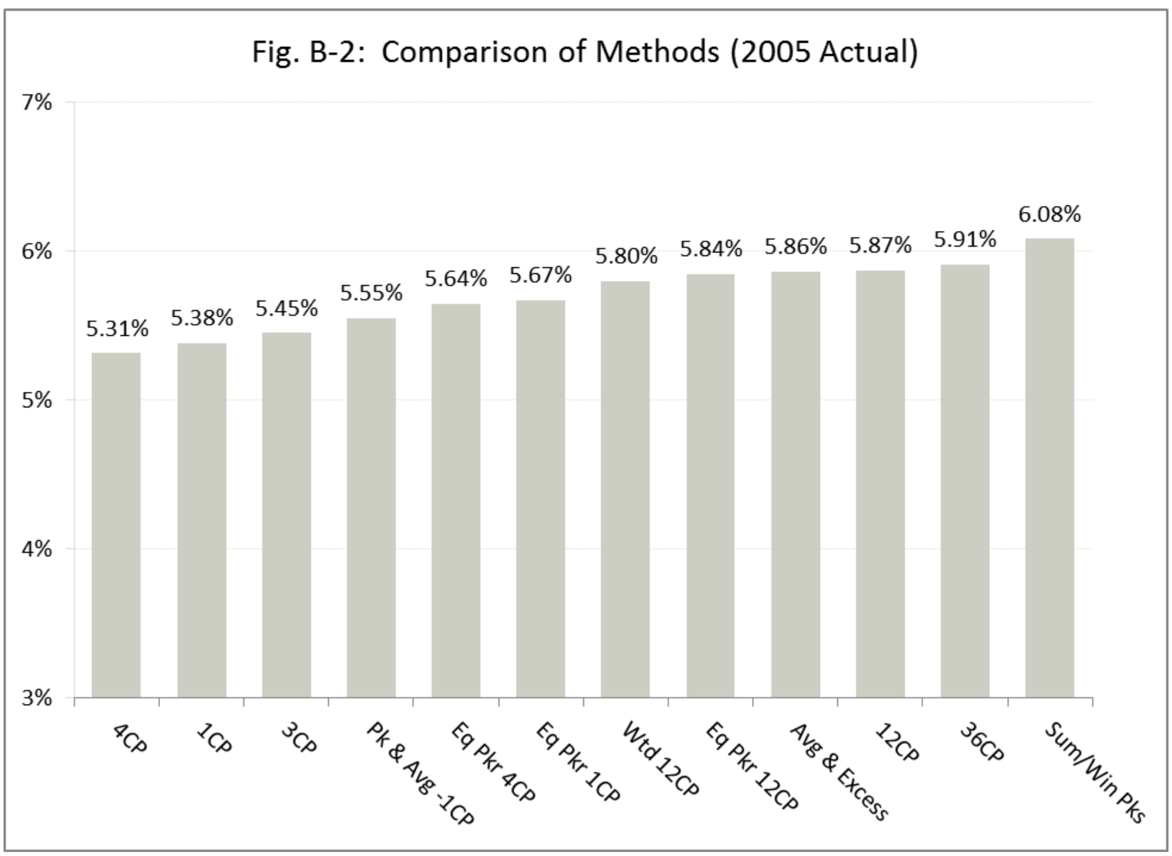


Fig. B-2: Comparison of Methods (2005 Actual)
7%
6%
5%
4%
3%
5.31%
5.38%
5.45%
5.55%
5.64%
5.67%
5.80%
5.84%
5.86%
5.87%
5.91%
6.08%
4CP
1CP
3CP
Pk & Avg -1CP
Eq Pkr 4CP
Eq Pkr 1CP
Wtd 12CP
Eq Pkr 12CP
Avg & Excess
12CP
36CP
Sum/Win Pks

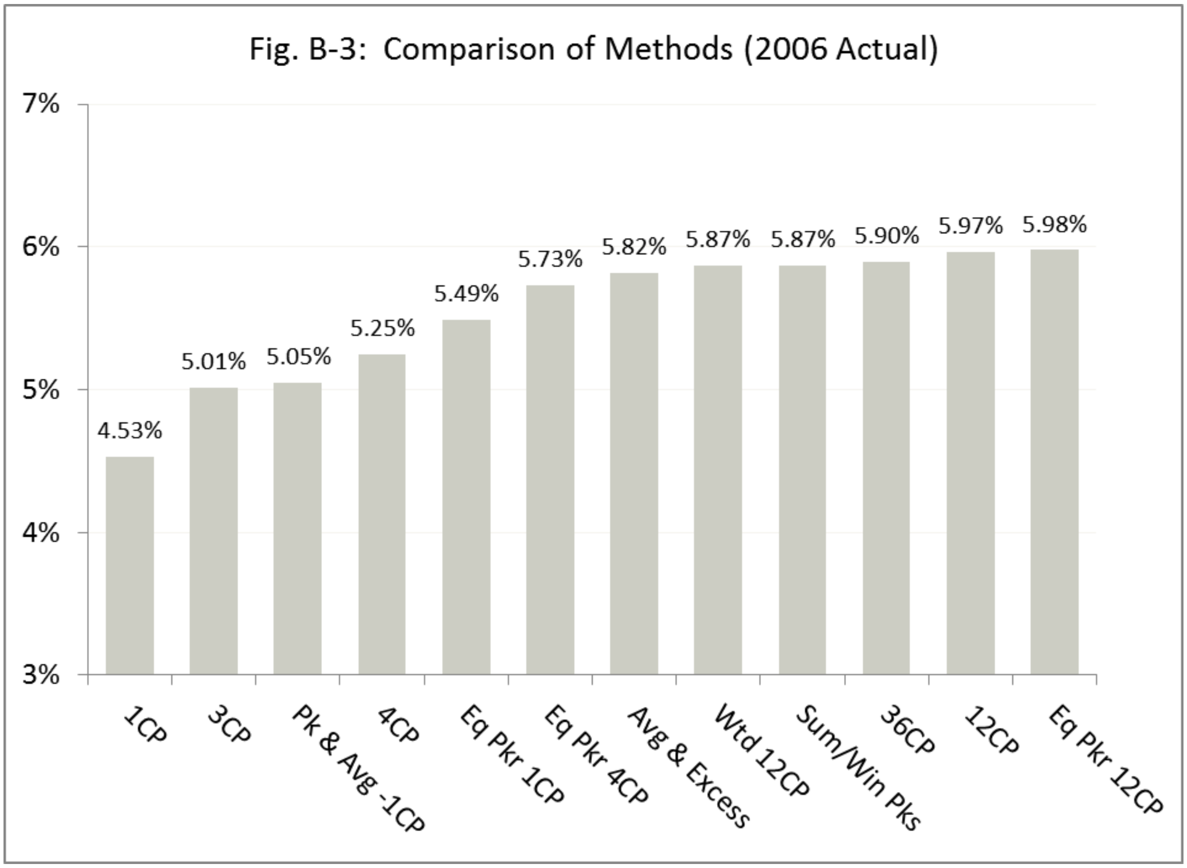


Fig. B-3: Comparison of Methods (2006 Actual)
7%
6%
5%
4%
3%
4.53%
5.01%
5.05%
5.25%
5.49%
5.73%
5.82%
5.87%
5.87%
5.90%
5.97%
5.98%
1CP
3CP
Pk & Avg -1CP
4CP
Eq Pkr 1CP
Eq Pkr 4CP
Avg & Excess
Wtd 12CP
Sum/Win Pks
36CP
12CP
Eq Pkr 12CP

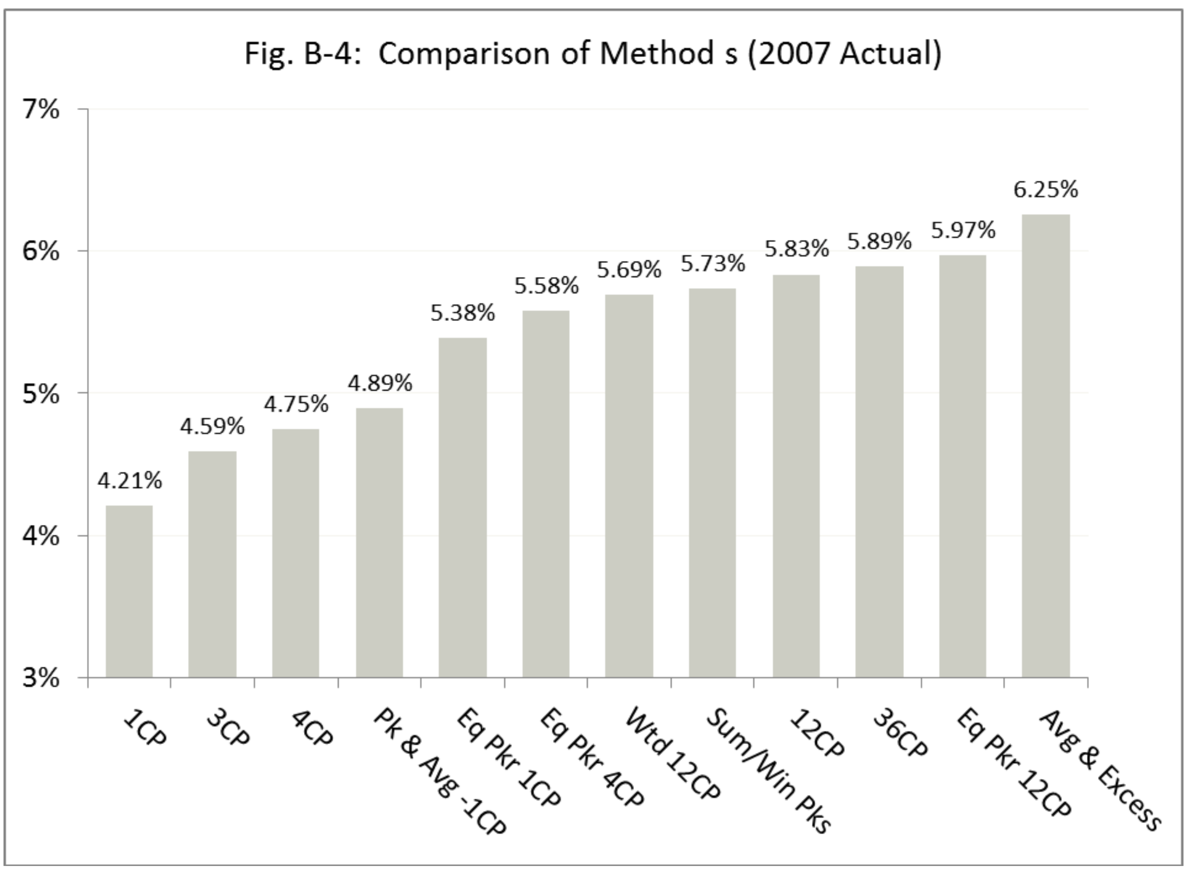


Fig. B-4: Comparison of Method s (2007 Actual)
7%
6%
5%
4%
3%
4.21%
4.59%
4.75%
4.89%
5.38%
5.58%
5.69%
5.73%
5.83%
5.89%
5.97%
6.25%
1CP
3CP
4CP
Pk & Avg -1CP
Eq Pkr 1CP
Eq Pkr 4CP
Wtd 12CP
Sum/Win Pks
12CP
36CP
Eq Pkr 12CP
Avg & Excess

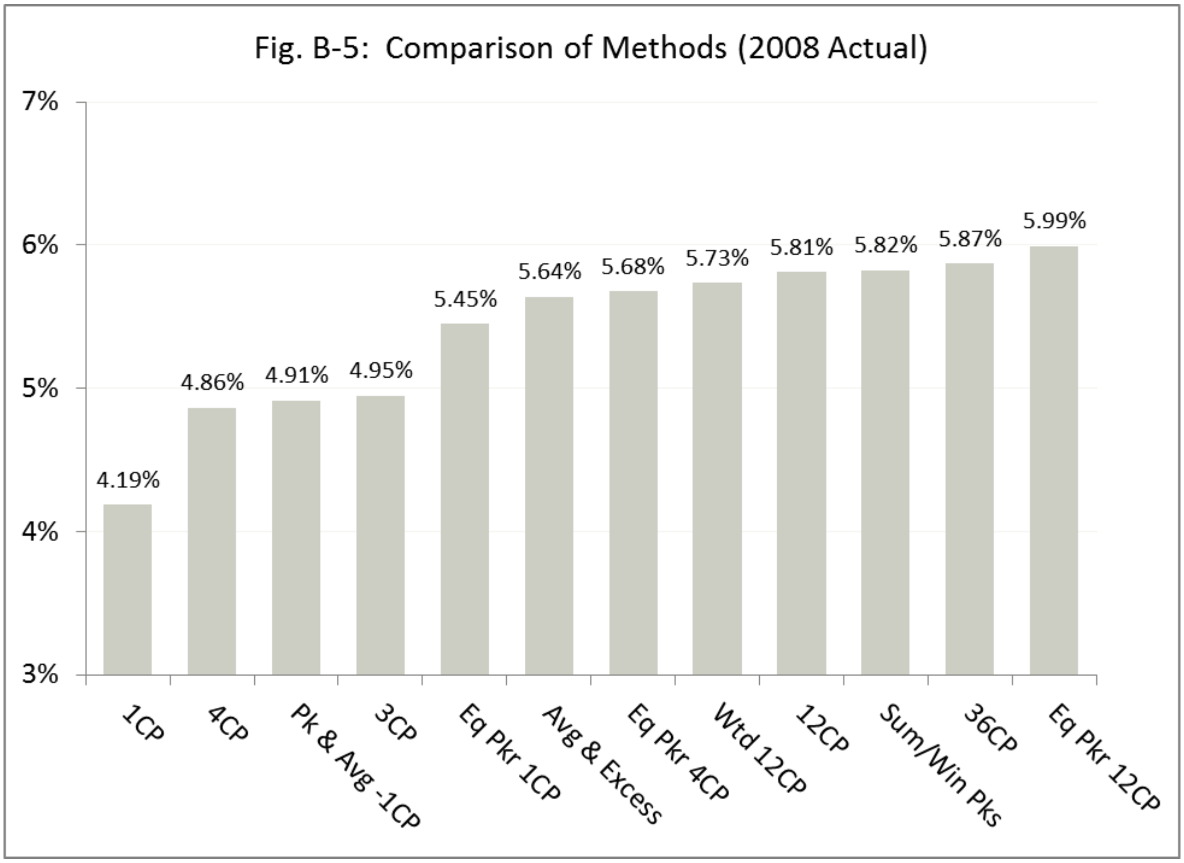


Fig. B-5: Comparison of Methods (2008 Actual)
7%
6%
5%
4%
3%
4.19%
4.86%
4.91%
4.95%
5.45%
5.64%
5.68%
5.73%
5.81%
5.82%
5.87%
5.99%
1CP
4CP
Pk & Avg -1CP
3CP
Eq Pkr 1CP
Avg & Excess
Eq Pkr 4CP
Wtd 12CP
12CP
Sum/Win Pks
36CP
Eq Pkr 12CP

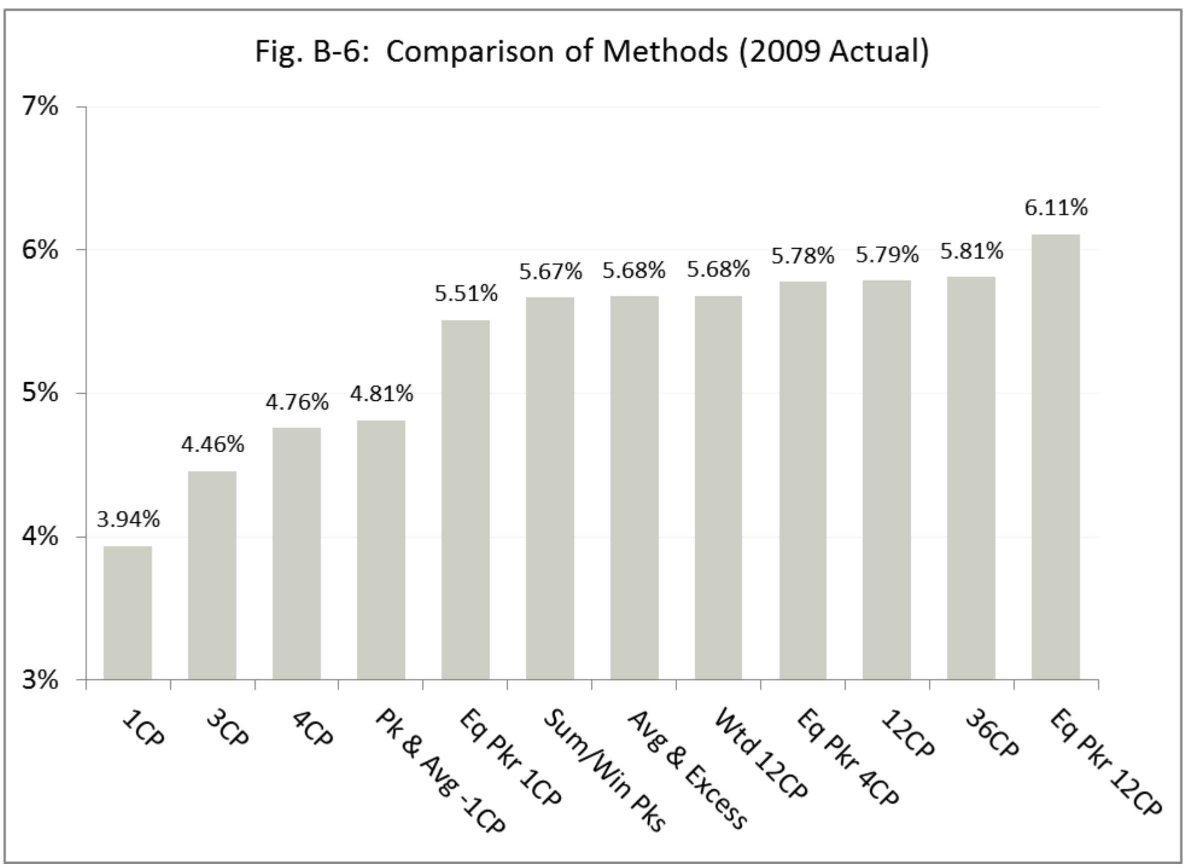


Fig. B-6: Comparison of Methods (2009 Actual)
7%
6%
5%
4%
3%
3.94%
4.46%
4.76%
4.81%
5.51%
5.67%
5.68%
5.68%
5.78%
5.79%
5.81%
6.11%
1CP
3CP
4CP
Pk & Avg -1CP
Eq Pkr 1CP
Sum/Win Pks
Avg & Excess
Wtd 12CP
Eq Pkr 4CP
12CP
36CP
Eq Pkr 12CP

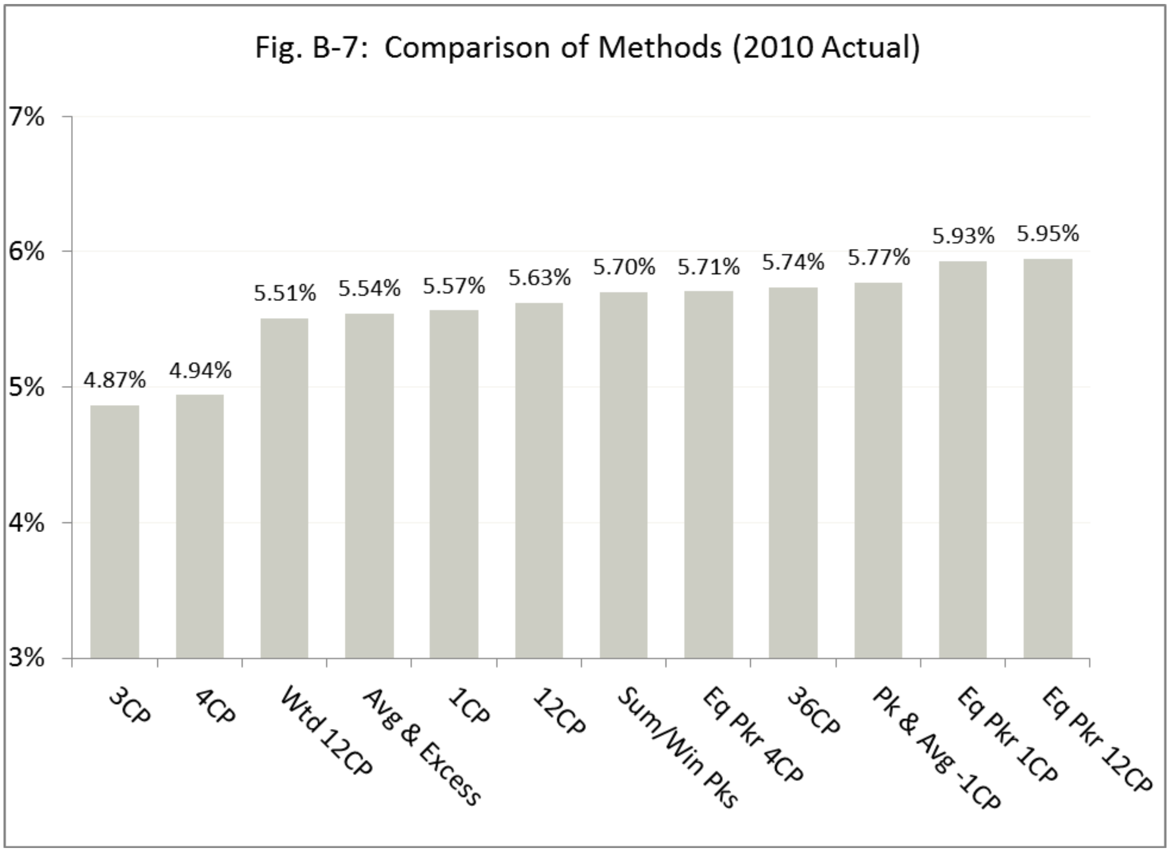


Fig. B-7: Comparison of Methods (2010 Actual)
7%
6%
5%
4%
3%
4.87%
4.94%
5.51%
5.54%
5.57%
5.63%
5.70%
5.71%
5.74%
5.77%
5.93%
5.95%
3CP
4CP
Wtd 12CP
Avg & Excess
1CP
12CP
Sum/Win Pks
Eq Pkr 4CP
36CP
Pk & Avg -1CP
Eq Pkr 1CP
Eq Pkr 12CP

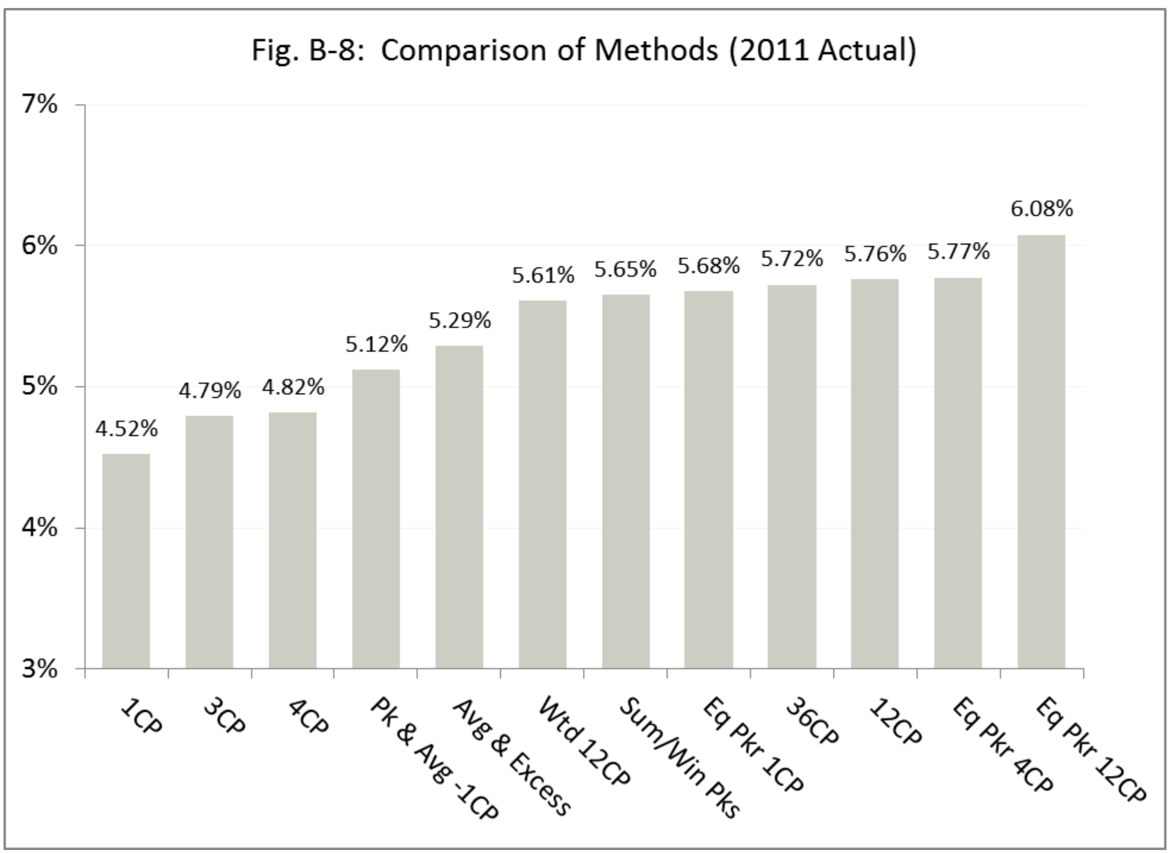


Fig. B-8: Comparison of Methods (2011 Actual)
7%
6%
5%
4%
3%
4.52%
4.79%
4.82%
5.12%
5.29%
5.61%
5.65%
5.68%
5.72%
5.76%
5.77%
6.08%
1CP
3CP
4CP
Pk & Avg -1CP
Avg & Excess
Wtd 12CP
Sum/Win Pks
Eq Pkr 1CP
36CP
12CP
Eq Pkr 4CP
Eq Pkr 12CP

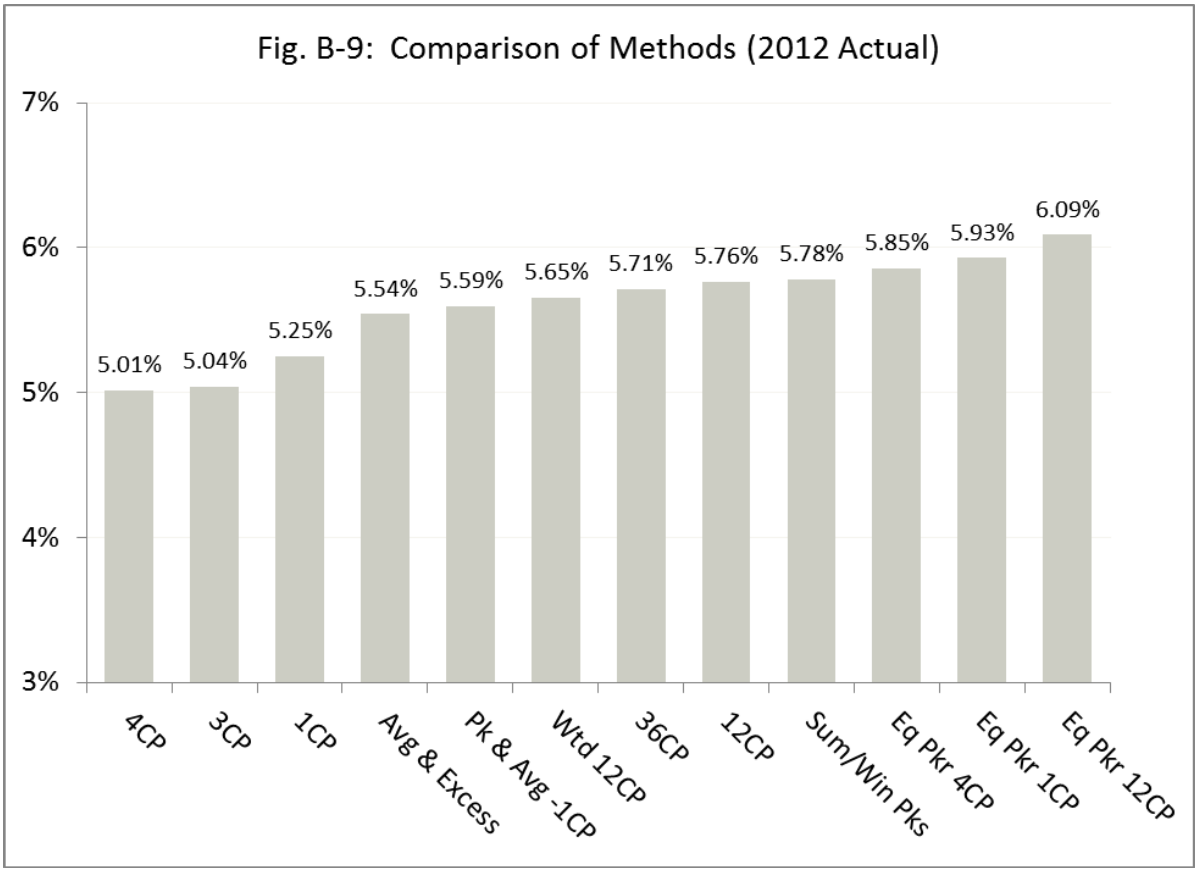


Fig. B-9: Comparison of Methods (2012 Actual)
7%
6%
5%
4%
3%
5.01%
5.04%
5.25%
5.54%
5.59%
5.65%
5.71%
5.76%
5.78%
5.85%
5.93%
6.09%
4CP
3CP
1CP
Avg & Excess
Pk & Avg -1CP
Wtd 12CP
36CP
12CP
Sum/Win Pks
Eq Pkr 4CP
Eq Pkr 1CP
Eq Pkr 12CP

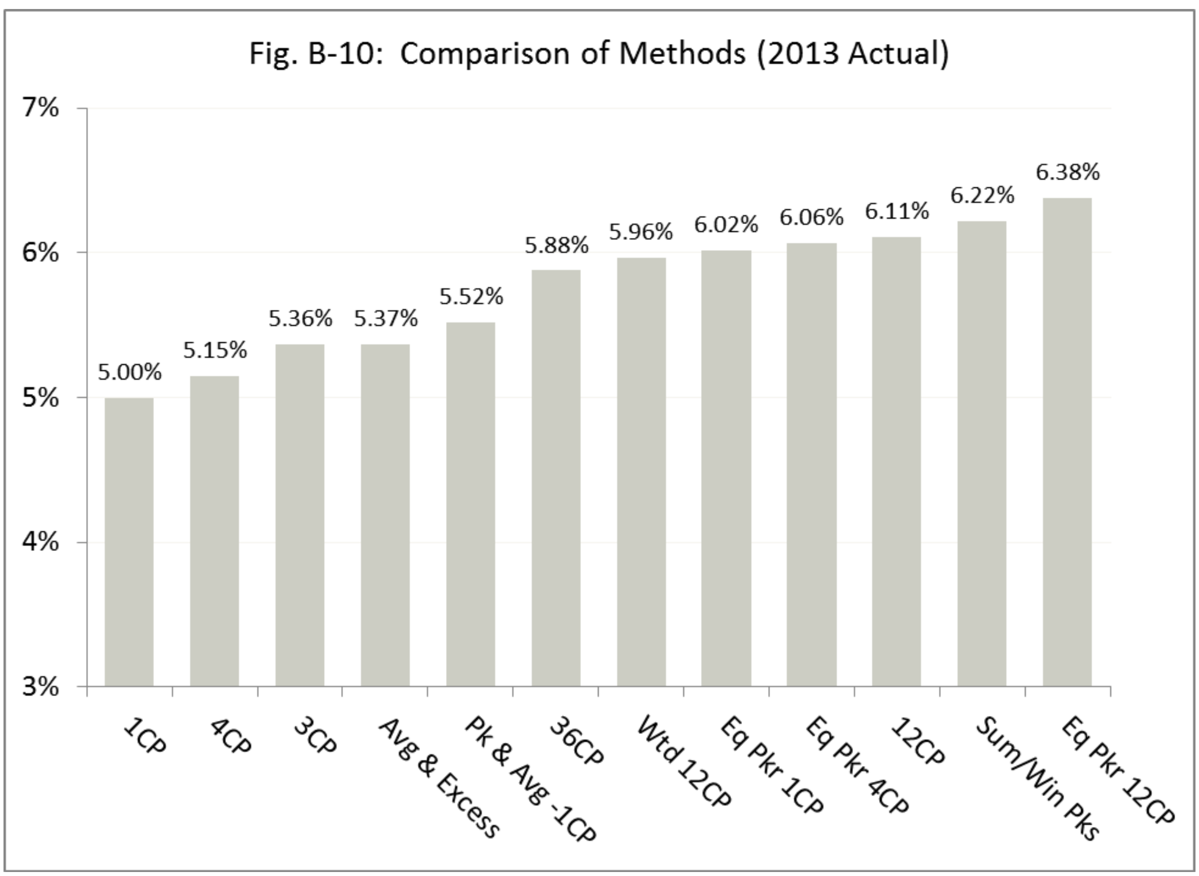


Fig. B-10: Comparison of Methods (2013 Actual)
7%
6%
5%
4%
3%
5.00%
5.15%
5.36%
5.37%
5.52%
5.88%
5.96%
6.02%
6.06%
6.11%
6.22%
6.38%
1CP
4CP
3CP
Avg & Excess
Pk & Avg -1CP
36CP
Wtd 12CP
Eq Pkr 1CP
Eq Pkr 4CP
12CP
Sum/Win Pks
Eq Pkr 12CP

Appendix C: Supporting Calculations of Assessment

Appendix C includes support for the calculation of the ratios used to assess how stable, predictable, and how effective each method studied is in terms of allowing NSPM an opportunity to fully recover its integrated system costs. Information is provided here to establish an audit trail for the calculations used to rank each method's performance in each of these three assessment criteria.

Table C-1: Allocation Factors and Derivation of Performance Indicators

		1CP												
North Dakota	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**ND Min**	**ND Max**	**Range**	**Mean**
Budget		5.085%	5.044%	5.244%	5.268%	4.797%	5.335%	5.151%	5.088%	5.497%	4.797%	5.497%	0.700%	5.17%
Actual	4.943%	5.380%	4.530%	4.208%	4.185%	3.937%	5.565%	4.520%	5.251%	4.996%	3.937%	5.565%	1.628%	4.73%
Actual vs. Budget		0.295%	-0.514%	-1.036%	-1.083%	-0.860%	0.230%	-0.631%	0.162%	-0.502%	Avg Abs Dev (Act vs Bud):			0.590%
Weather Normalized	4.905%	5.398%	4.449%	5.376%	5.529%	4.681%	4.561%	4.417%	5.210%	4.946%	4.417%	5.529%	1.112%	4.95%
WN vs. Budget		0.314%	-0.596%	0.132%	0.261%	-0.116%	-0.774%	-0.734%	0.122%	-0.551%				
Actual "Best Fit" Trend	4.660%	4.680%	4.701%	4.721%	4.741%	4.762%	4.782%	4.802%	4.822%	4.843%				
Act vs Best Fit	0.282%	0.700%	-0.171%	-0.513%	-0.556%	-0.824%	0.784%	-0.282%	0.428%	0.153%	RMSE (vs Best Fit Linear):			0.524%
Act vs 12CP Act	-0.909%	-0.490%	-1.435%	-1.625%	-1.624%	-1.849%	-0.060%	-1.238%	-0.510%	-1.114%	Avg Dev (Act vs 12CP):			-1.105%
		3CP												
North Dakota	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**ND Min**	**ND Max**	**Range**	**Mean**
Budget		4.868%	4.820%	5.089%	5.297%	4.846%	4.882%	4.742%	4.929%	5.024%	4.742%	5.297%	0.555%	4.94%
Actual	5.009%	5.450%	5.011%	4.589%	4.948%	4.458%	4.868%	4.793%	5.039%	5.364%	4.458%	5.364%	0.905%	4.95%
Actual vs. Budget		0.582%	0.191%	-0.500%	-0.349%	-0.387%	-0.014%	0.051%	0.110%	0.340%	Avg Abs Dev (Act vs Bud):			0.280%
Weather Normalized	5.007%	5.438%	5.016%	4.561%	4.988%	4.489%	4.865%	4.749%	5.028%	5.350%	4.489%	5.350%	0.861%	4.94%
WN vs. Budget		0.570%	0.196%	-0.528%	-0.309%	-0.357%	-0.016%	0.007%	0.099%	0.326%				
Actual "Best Fit" Trend	4.965%	4.962%	4.960%	4.957%	4.954%	4.952%	4.949%	4.947%	4.944%	4.941%				
Act vs Best Fit	0.044%	0.488%	0.051%	-0.368%	-0.006%	-0.493%	-0.081%	-0.153%	0.095%	0.422%	RMSE (vs Best Fit Linear):			0.290%
Act vs 12CP Act	-0.843%	-0.420%	-0.954%	-1.243%	-0.861%	-1.327%	-0.757%	-0.965%	-0.722%	-0.746%	Avg Dev (Act vs 12CP):			-0.888%
		4CP												
North Dakota	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**ND Min**	**ND Max**	**Range**	**Mean**
Budget		4.906%	4.872%	5.104%	5.316%	4.924%	5.016%	4.890%	5.004%	5.187%	4.872%	5.316%	0.444%	5.02%
Actual	5.018%	5.313%	5.250%	4.747%	4.865%	4.760%	4.942%	4.815%	5.013%	5.147%	4.747%	5.250%	0.503%	4.98%
Actual vs. Budget		0.407%	0.378%	-0.357%	-0.452%	-0.164%	-0.074%	-0.075%	0.009%	-0.040%	Avg Abs Dev (Act vs Bud):			0.217%
Weather Normalized	5.004%	5.286%	5.263%	4.704%	4.945%	4.791%	4.981%	4.749%	5.020%	5.119%	4.704%	5.263%	0.559%	4.98%
WN vs. Budget		0.379%	0.391%	-0.400%	-0.372%	-0.133%	-0.035%	-0.141%	0.016%	-0.067%				
Actual "Best Fit" Trend	5.059%	5.043%	5.027%	5.011%	4.995%	4.979%	4.963%	4.947%	4.931%	4.915%				
Act vs Best Fit	-0.041%	0.270%	0.223%	-0.264%	-0.130%	-0.219%	-0.021%	-0.132%	0.082%	0.232%	RMSE (vs Best Fit Linear):			0.184%
Act vs 12CP Act	-0.834%	-0.557%	-0.715%	-1.085%	-0.944%	-1.026%	-0.684%	-0.943%	-0.747%	-0.963%	Avg Dev (Act vs 12CP):			-0.852%
		Summer/Winter Peaks												
North Dakota	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**ND Min**	**ND Max**	**Range**	**Mean**
Budget		5.701%	5.655%	5.844%	5.982%	5.632%	5.857%	5.799%	5.853%	5.986%	5.632%	5.986%	0.354%	5.81%
Actual	5.867%	6.081%	5.870%	5.731%	5.821%	5.665%	5.702%	5.648%	5.782%	6.215%	5.648%	6.215%	0.567%	5.84%
Actual vs. Budget		0.380%	0.214%	-0.113%	-0.161%	0.034%	-0.155%	-0.151%	-0.071%	0.229%	Avg Abs Dev (Act vs Bud):			0.168%
Weather Normalized	5.866%	6.080%	5.873%	5.726%	5.824%	5.668%	5.701%	5.642%	5.782%	6.215%	5.642%	6.215%	0.574%	5.83%
WN vs. Budget		0.379%	0.217%	-0.118%	-0.158%	0.036%	-0.156%	-0.158%	-0.071%	0.230%				
Actual "Best Fit" Trend	5.847%	5.845%	5.843%	5.841%	5.839%	5.837%	5.835%	5.834%	5.832%	5.830%				
Act vs Best Fit	0.020%	0.236%	0.027%	-0.110%	-0.018%	-0.172%	-0.134%	-0.185%	-0.050%	0.385%	RMSE (vs Best Fit Linear):			0.174%
Act vs 12CP Act	0.015%	0.211%	-0.095%	-0.101%	0.012%	-0.121%	0.077%	-0.110%	0.021%	0.106%	Avg Dev (Act vs 12CP):			0.000%
		12CP												
North Dakota	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**ND Min**	**ND Max**	**Range**	**Mean**
Budget		5.675%	5.617%	5.748%	5.895%	5.629%	5.897%	5.818%	5.840%	6.026%	5.617%	6.026%	0.409%	5.79%
Actual	5.852%	5.870%	5.965%	5.832%	5.809%	5.786%	5.625%	5.758%	5.761%	6.110%	5.625%	6.110%	0.484%	5.84%
Actual vs. Budget		0.195%	0.348%	0.085%	-0.086%	0.157%	-0.272%	-0.060%	-0.079%	0.083%	Avg Abs Dev (Act vs Bud):			0.152%
Weather Normalized	5.858%	5.870%	5.968%	5.824%	5.819%	5.787%	5.625%	5.756%	5.761%	6.109%	5.625%	6.109%	0.483%	5.84%
WN vs. Budget		0.195%	0.351%	0.077%	-0.076%	0.158%	-0.272%	-0.062%	-0.079%	0.082%				
Actual "Best Fit" Trend	5.840%	5.840%	5.839%	5.838%	5.837%	5.836%	5.836%	5.835%	5.834%	5.833%				
Act vs Best Fit	0.012%	0.031%	0.126%	-0.006%	-0.028%	-0.050%	-0.210%	-0.077%	-0.073%	0.276%	RMSE (vs Best Fit Linear):			0.123%
Act vs 12CP Act	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	Avg Dev (Act vs 12CP):			0.000%
		Weighted 12CP												
North Dakota	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**ND Min**	**ND Max**	**Range**	**Mean**
Budget		5.582%	5.525%	5.693%	5.828%	5.535%	5.806%	5.723%	5.755%	5.916%	5.525%	5.916%	0.391%	5.71%
Actual	5.761%	5.798%	5.869%	5.690%	5.734%	5.681%	5.508%	5.606%	5.652%	5.962%	5.508%	5.962%	0.454%	5.72%
Actual vs. Budget		0.216%	0.344%	-0.003%	-0.094%	0.147%	-0.298%	-0.116%	-0.102%	0.046%	Avg Abs Dev (Act vs Bud):			0.152%
Weather Normalized	5.767%	5.810%	5.879%	5.696%	5.716%	5.683%	5.525%	5.628%	5.651%	5.969%	5.525%	5.969%	0.445%	5.73%
WN vs. Budget		0.227%	0.354%	0.003%	-0.112%	0.149%	-0.281%	-0.094%	-0.104%	0.053%				
Actual "Best Fit" Trend	5.757%	5.750%	5.743%	5.736%	5.730%	5.723%	5.716%	5.709%	5.702%	5.695%				
Act vs Best Fit	0.004%	0.048%	0.126%	-0.047%	0.004%	-0.041%	-0.208%	-0.103%	-0.050%	0.266%	RMSE (vs Best Fit Linear):			0.122%
Act vs 12CP Act	-0.091%	-0.072%	-0.096%	-0.143%	-0.075%	-0.105%	-0.117%	-0.152%	-0.108%	-0.148%	Avg Dev (Act vs 12CP):			-0.113%

Notes:

Avg Abs Dev (Act vs Bud): Measure of how much actual allocation factors differ from forecasted (budgeted) factors. "Abs" refers to the absolute value of annual deviations; the measure reflects the average annual difference over the period from 2005 to 2013.

RMSE (vs Best Fit Linear): Measure of how much actual allocation factors differ from the linear trend line of the plotted data points. "RMSE" refers to the "root mean square error"; essentially the root of the sum of the differences squared.

Avg Dev (Act vs 12CP): Measure of the average annual difference between the given method and the 12CP method currently used by NSPM in ND and its other jurisdictions. A positive result indicates that an "over-recovery" of costs would occur over the 10 year period; a negative result indicates an "under-recovery".

Table C-1 (cont.): Allocation Factors and Derivation of Performance Indicators

						36CP								
North Dakota	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**ND Min**	**ND Max**	**Range**	**Mean**
Budget		5.844%	5.713%	5.744%	5.869%	5.786%	5.777%	5.834%	5.761%	5.874%	5.713%	5.874%	0.161%	5.80%
Actual	5.884%	5.912%	5.896%	5.889%	5.869%	5.810%	5.738%	5.722%	5.715%	5.876%	5.715%	5.896%	0.181%	5.83%
Actual vs. Budget		0.067%	0.183%	0.145%	0.000%	0.024%	-0.039%	-0.112%	-0.047%	0.002%	Avg Abs Dev (Act vs Bud):			0.069%
Weather Normalized	5.886%	5.914%	5.899%	5.887%	5.870%	5.810%	5.742%	5.722%	5.714%	5.875%	5.714%	5.899%	0.185%	5.83%
WN vs. Budget		0.070%	0.187%	0.144%	0.001%	0.024%	-0.035%	-0.113%	-0.047%	0.001%				
Actual "Best Fit" Trend	5.908%	5.891%	5.874%	5.857%	5.840%	5.822%	5.805%	5.788%	5.771%	5.754%				
Act vs Best Fit	-0.024%	0.020%	0.022%	0.032%	0.029%	-0.013%	-0.067%	-0.066%	-0.056%	0.122%	RMSE (vs Best Fit Linear):			0.055%
Act vs 12CP Act	0.032%	0.041%	-0.069%	0.056%	0.060%	0.024%	0.113%	-0.036%	-0.046%	-0.234%	Avg Dev (Act vs 12CP):			-0.010%
						Equivalent Peaker 1CP								
North Dakota	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**ND Min**	**ND Max**	**Range**	**Mean**
Budget		5.660%	5.591%	5.617%	5.760%	5.688%	5.918%	5.909%	5.910%	6.192%	5.591%	6.192%	0.600%	5.81%
Actual	5.666%	5.669%	5.489%	5.385%	5.448%	5.511%	5.929%	5.677%	5.927%	6.016%	5.385%	6.016%	0.631%	5.67%
Actual vs. Budget		0.009%	-0.103%	-0.232%	-0.312%	-0.177%	0.011%	-0.232%	0.017%	-0.176%	Avg Abs Dev (Act vs Bud):			0.141%
Weather Normalized	5.873%	5.953%	5.614%	5.931%	5.934%	5.747%	5.618%	5.669%	5.994%	5.993%	5.614%	5.994%	0.380%	5.83%
WN vs. Budget		0.293%	0.023%	0.314%	0.174%	0.060%	-0.300%	-0.240%	0.084%	-0.198%				
Actual "Best Fit" Trend	5.465%	5.511%	5.557%	5.603%	5.649%	5.695%	5.741%	5.787%	5.833%	5.879%				
Act vs Best Fit	0.202%	0.158%	-0.068%	-0.218%	-0.201%	-0.184%	0.189%	-0.110%	0.094%	0.137%	RMSE (vs Best Fit Linear):			0.163%
Act vs 12CP Act	-0.186%	-0.202%	-0.476%	-0.448%	-0.361%	-0.275%	0.304%	-0.081%	0.166%	-0.094%	Avg Dev (Act vs 12CP):			-0.163%
						Equivalent Peaker 4CP								
North Dakota	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**ND Min**	**ND Max**	**Range**	**Mean**
Budget		5.596%	5.533%	5.567%	5.776%	5.729%	5.804%	5.825%	5.884%	6.092%	5.533%	6.092%	0.559%	5.76%
Actual	5.693%	5.645%	5.734%	5.578%	5.676%	5.778%	5.706%	5.772%	5.853%	6.065%	5.578%	6.065%	0.487%	5.76%
Actual vs. Budget		0.049%	0.201%	0.010%	-0.100%	0.049%	-0.097%	-0.053%	-0.031%	-0.027%	Avg Abs Dev (Act vs Bud):			0.069%
Weather Normalized	5.909%	5.912%	5.891%	5.691%	5.738%	5.783%	5.768%	5.776%	5.935%	6.049%	5.691%	6.049%	0.358%	5.84%
WN vs. Budget		0.317%	0.358%	0.124%	-0.038%	0.054%	-0.035%	-0.049%	0.051%	-0.042%				
Actual "Best Fit" Trend	5.601%	5.634%	5.667%	5.700%	5.733%	5.767%	5.800%	5.833%	5.866%	5.899%				
Act vs Best Fit	0.093%	0.011%	0.067%	-0.123%	-0.057%	0.011%	-0.093%	-0.061%	-0.013%	0.165%	RMSE (vs Best Fit Linear):			0.085%
Act vs 12CP Act	-0.159%	-0.225%	-0.231%	-0.255%	-0.133%	-0.008%	0.081%	0.014%	0.092%	-0.045%	Avg Dev (Act vs 12CP):			-0.079%
						Equivalent Peaker 12CP								
North Dakota	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**ND Min**	**ND Max**	**Range**	**Mean**
Budget		5.871%	5.786%	5.797%	5.970%	5.957%	6.119%	6.124%	6.146%	6.362%	5.786%	6.362%	0.576%	6.01%
Actual	5.991%	5.844%	5.977%	5.965%	5.993%	6.111%	5.951%	6.076%	6.087%	6.375%	5.951%	6.375%	0.424%	6.04%
Actual vs. Budget		-0.027%	0.191%	0.168%	0.023%	0.153%	-0.168%	-0.048%	-0.059%	0.013%	Avg Abs Dev (Act vs Bud):			0.094%
Weather Normalized	6.214%	6.121%	6.131%	6.091%	6.031%	6.106%	5.999%	6.100%	6.167%	6.368%	5.999%	6.368%	0.370%	6.12%
WN vs. Budget		0.251%	0.345%	0.294%	0.061%	0.148%	-0.120%	-0.024%	0.021%	0.006%				
Actual "Best Fit" Trend	5.881%	5.916%	5.950%	5.985%	6.020%	6.054%	6.089%	6.124%	6.158%	6.193%				
Act vs Best Fit	0.110%	-0.072%	0.027%	-0.020%	-0.027%	0.056%	-0.138%	-0.048%	-0.072%	0.182%	RMSE (vs Best Fit Linear):			0.091%
Act vs 12CP Act	0.139%	-0.026%	0.012%	0.133%	0.184%	0.325%	0.325%	0.318%	0.326%	0.265%	Avg Dev (Act vs 12CP):			0.207%
						Average & Excess								
North Dakota	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**ND Min**	**ND Max**	**Range**	**Mean**
Budget		6.172%	6.338%	6.797%	5.542%	5.884%	5.977%	5.817%	5.957%	5.621%	5.542%	6.797%	1.255%	6.01%
Actual	5.568%	5.861%	5.820%	6.252%	5.639%	5.676%	5.543%	5.291%	5.540%	5.365%	5.291%	6.252%	0.960%	5.67%
Actual vs. Budget		-0.310%	-0.519%	-0.545%	0.097%	-0.208%	-0.434%	-0.526%	-0.417%	-0.256%	Avg Abs Dev (Act vs Bud):			0.368%
Weather Normalized	5.898%	6.186%	6.331%	6.820%	5.565%	5.918%	5.955%	5.796%	5.920%	5.502%	5.502%	6.820%	1.318%	6.00%
WN vs. Budget		0.014%	-0.007%	0.023%	0.023%	0.034%	-0.022%	-0.022%	-0.036%	-0.119%				
Actual "Best Fit" Trend	5.896%	5.842%	5.789%	5.735%	5.682%	5.629%	5.575%	5.522%	5.469%	5.415%				
Act vs Best Fit	-0.328%	0.019%	0.031%	0.516%	-0.043%	0.047%	-0.032%	-0.231%	0.071%	-0.050%	RMSE (vs Best Fit Linear):			0.210%
Act vs 12CP Act	-0.284%	-0.009%	-0.145%	0.419%	-0.170%	-0.110%	-0.082%	-0.466%	-0.221%	-0.744%	Avg Dev (Act vs 12CP):			-0.170%
						Peak & Average with 1CP								
North Dakota	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**ND Min**	**ND Max**	**Range**	**Mean**
Budget		5.412%	5.343%	5.462%	5.537%	5.292%	5.678%	5.571%	5.541%	5.878%	5.292%	5.878%	0.586%	5.52%
Actual	5.342%	5.547%	5.051%	4.890%	4.910%	4.813%	5.771%	5.120%	5.594%	5.517%	4.813%	5.771%	0.957%	5.25%
Actual vs. Budget		0.135%	-0.293%	-0.572%	-0.627%	-0.478%	0.093%	-0.451%	0.052%	-0.361%	Avg Abs Dev (Act vs Bud):			0.340%
Weather Normalized	5.462%	5.719%	5.105%	5.701%	5.757%	5.287%	5.161%	5.094%	5.618%	5.493%	5.094%	5.757%	0.663%	5.44%
WN vs. Budget		0.307%	-0.239%	0.239%	0.220%	-0.005%	-0.516%	-0.477%	0.076%	-0.385%				
Actual "Best Fit" Trend	5.125%	5.154%	5.183%	5.212%	5.241%	5.270%	5.299%	5.328%	5.357%	5.386%				
Act vs Best Fit	0.217%	0.393%	-0.132%	-0.322%	-0.331%	-0.456%	0.472%	-0.208%	0.237%	0.131%	RMSE (vs Best Fit Linear):			0.313%
Act vs 12CP Act	-0.510%	-0.323%	-0.914%	-0.942%	-0.899%	-0.972%	0.145%	-0.638%	-0.167%	-0.593%	Avg Dev (Act vs 12CP):			-0.589%

Notes:

Avg Abs Dev (Act vs Bud): Measure of how much actual allocation factors differ from forecasted (budgeted) factors. "Abs" refers to the absolute value of annual deviations; the measure reflects the average annual difference over the period from 2005 to 2013.

RMSE (vs Best Fit Linear): Measure of how much actual allocation factors differ from the linear trend line of the plotted data points. "RMSE" refers to the "root mean square error"; essentially the root of the sum of the differences squared.

Avg Dev (Act vs 12CP): Measure of the average annual difference between the given method and the 12CP method currently used by NSPM in ND and its other jurisdictions. A positive result indicates that an "over-recovery" of costs would occur over the 10 year period; a negative result indicates an "under-recovery".

Appendix D: Stratification of NSP Generation

Appendix D describes the calculations made to segment NSPM's generation investments into "capacity-related" and "energy-related" categories. This stratification is performed for the purposes of developing the allocation factors for the Equivalent Peaker family of methods. The calculation allows the appropriate weighting of the impacts of jurisdictional coincident peak demands and annual energy use on overall system investments and costs.

Plant Stratification

Plant stratification is the terminology used by the Company for the analysis used to separate generation plant fixed costs into energy (baseload) and capacity (peaking-related components). This cost separation process is similar to the method described on page 52 of the NARUC Electric Utility Cost Allocation manual for the Equivalent Peaker method.

The stratification process starts by calculating the replacement costs of each company-owned generation plant in dollars per kW. For each plant type, the capacity-related component of fixed costs is based on the ratio of the fixed costs of a combustion turbine peaking plant (the generation source with the lowest capital cost for meeting customer demand) to the fixed costs of each generation type. The percent of generation costs that exceeds the cost of a comparable peaking plant are classified as energy related. These costs are in excess of the capacity-related portion, and as such, were not incurred to obtain capacity, but rather to obtain lower cost energy that such plants can produce. The capacity versus baseload splits that were applied in the Company's last ND rate case (Case No. PU-12-813) are shown in the table below for each plant type.

Table D-1

Plant Type	$/kW	Capacity Ratio	Capacity %	Energy %
Peaking (CT)	$689	$689 / $689	100.0%	0.0%
Nuclear	$3,678	$689 / $3,678	18.7%	81.3%
Fossil	$1,912	$689 / $1,912	36.0%	64.0%
Combined Cycle	$997	$689 / $997	69.1%	30.9%
Hydro	$4,474	$689 / $4,474	15.4%	84.6%
Wind	$15,297	$689 / $15,297	4.5%	95.5%

This process of "stratifying" the fixed generation plant costs is accomplished by applying these stratification percents to each component of revenue requirements (plant investment, accumulated depreciation, deferred income taxes, construction work in progress, etc.), for each generation plant type. After costs are split into baseload and capacity components, the baseload portion is allocated using an energy allocator, while the peaking or capacity-related portion is allocated using a demand allocator.

APPENDIX E: DEMAND AND ENERGY DATA BY YEAR

Appendix E includes jurisdictional peak demand and energy data used to calculate the historical allocation factors for each method studied. Data is provided on an actual, weather-normalized actual and budget basis.

Table E-1: Coincident Peak Demand (NSPM) - Actual

1CP Demand (KW)

Jurisdiction	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	6,351,071	6,155,465	6,594,088	6,340,866	6,212,375	6,202,742	6,572,012	6,981,679	6,933,708	6,972,464
ND	349,939	370,844	332,689	296,266	288,423	267,087	413,160	352,616	406,911	392,183
SD	379,148	366,578	417,634	403,972	390,762	313,670	438,524	466,568	409,289	486,021
Total Retail	7,080,157	6,892,887	7,344,411	7,041,104	6,891,559	6,783,499	7,423,695	7,800,863	7,749,908	7,850,669

3CP Demand (KW)

Jurisdiction	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	18,084,445	18,381,632	18,378,118	18,902,793	17,924,527	17,411,433	19,112,982	19,755,399	19,545,931	19,546,566
ND	1,010,927	1,123,429	1,028,602	960,718	990,499	862,496	1,042,599	1,060,616	1,111,041	1,184,928
SD	1,085,425	1,106,683	1,120,163	1,070,418	1,102,027	1,071,158	1,260,968	1,311,641	1,391,249	1,359,424
Total Retail	20,180,797	20,611,744	20,526,882	20,933,929	20,017,053	19,345,087	21,416,548	22,127,656	22,048,221	22,090,918

4CP Demand (KW)

Jurisdiction	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	23,816,804	23,820,764	23,503,794	25,184,823	23,189,950	22,489,705	23,996,479	26,069,015	25,546,966	25,713,744
ND	1,332,637	1,418,694	1,381,985	1,327,941	1,254,779	1,193,487	1,329,466	1,407,659	1,443,576	1,493,933
SD	1,409,381	1,462,459	1,436,286	1,459,759	1,349,439	1,389,727	1,577,918	1,756,665	1,804,485	1,819,532
Total Retail	26,558,821	26,701,917	26,322,066	27,972,523	25,794,168	25,072,919	26,903,863	29,233,339	28,795,026	29,027,209

Sum/Win CP Demand (KW)

Jurisdiction	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	32,047,696	32,141,644	32,138,647	32,695,625	32,102,432	31,433,797	33,060,708	33,605,983	32,796,628	33,303,452
ND	2,112,705	2,203,285	2,121,866	2,104,339	2,107,988	2,004,795	2,129,814	2,145,146	2,152,440	2,360,413
SD	1,850,434	1,885,795	1,888,437	1,918,302	2,002,945	1,948,318	2,161,942	2,227,842	2,277,717	2,313,829
Total Retail	36,010,835	36,230,725	36,148,950	36,718,266	36,213,364	35,386,909	37,352,465	37,978,972	37,226,785	37,977,694

12CP Demand (KW)

Jurisdiction	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	59,275,169	60,299,432	60,163,360	62,053,205	58,577,579	58,298,756	61,681,492	61,939,042	60,829,723	60,848,480
ND	3,891,211	3,978,088	4,041,242	4,074,001	3,826,422	3,799,161	3,910,509	4,031,359	3,974,076	4,236,076
SD	3,327,462	3,489,250	3,544,622	3,723,105	3,467,451	3,563,849	3,923,283	4,045,443	4,182,120	4,248,380
Total Retail	66,493,841	67,766,770	67,749,223	69,850,312	65,871,451	65,661,766	69,515,284	70,015,845	68,985,919	69,332,936

Wtd 12CP Demand (KW)

Jurisdiction	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	72,396,086	73,318,093	74,607,486	78,975,538	71,689,379	72,329,829	78,658,287	81,017,793	79,709,092	80,109,378
ND	4,676,068	4,775,554	4,927,313	5,049,281	4,619,425	4,623,405	4,877,436	5,127,515	5,104,677	5,434,032
SD	4,089,792	4,271,361	4,417,335	4,721,747	4,256,106	4,425,493	5,016,715	5,316,110	5,495,030	5,606,364
Total Retail	81,161,945	82,365,007	83,952,134	88,746,566	80,564,910	81,378,727	88,552,438	91,461,418	90,308,799	91,149,773

36CP Demand (KW)

Jurisdiction	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	172,185,334	175,599,396	179,737,961	182,515,997	180,794,144	178,929,540	178,557,826	181,919,290	184,450,257	183,617,245
ND	11,363,686	11,651,270	11,910,540	12,093,330	11,941,665	11,699,584	11,536,092	11,741,030	11,915,945	12,241,511
SD	9,571,043	9,840,651	10,361,334	10,756,977	10,735,178	10,754,405	10,954,582	11,532,575	12,150,846	12,475,943
Total Retail	193,120,064	197,091,317	202,009,834	205,366,305	203,470,986	201,383,529	201,048,501	205,192,895	208,517,048	208,334,700

Table E-2: Miscellaneous Data for Factor Calculations - Actual

Stratification of Demand and Energy - % Split

Jurisdiction	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
% Capacity	35.73%	35.73%	34.05%	35.73%	33.56%	32.42%	35.73%	32.21%	31.29%	32.26%
% Baseload	64.27%	64.27%	65.95%	64.27%	66.44%	67.58%	64.27%	67.79%	68.71%	67.74%
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Non-Coincident Peak Demand (KW)

Jurisdiction	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	6,356,245	6,336,962	6,537,490	6,370,070	6,217,875	6,209,172	6,577,337	6,987,319	6,940,163	6,977,777
ND	397,356	420,016	432,415	456,055	396,213	396,213	413,361	416,807	434,959	423,147
SD	390,263	406,704	463,600	456,768	432,252	412,036	471,663	493,063	494,018	497,054
Total Retail	7,144,921	6,958,907	7,400,089	7,213,375	7,055,592	6,910,081	7,490,576	7,808,165	7,756,669	7,854,751

Energy (MWh)

Jurisdiction	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	30,403,203	31,711,834	31,926,534	32,478,773	33,030,118	31,596,109	32,628,729	32,612,821	31,997,188	31,882,826
ND	2,073,361	2,078,476	2,149,476	2,213,456	2,271,706	2,245,606	2,267,685	2,304,806	2,268,544	2,364,949
SD	1,687,634	1,866,144	1,847,003	1,960,443	2,026,038	1,994,260	2,086,639	2,095,088	2,116,631	2,126,776
Total Retail	34,164,198	35,656,454	35,923,013	36,652,672	37,327,862	35,835,975	36,983,053	37,012,714	36,382,362	36,374,552

Average Demand (KW)

Jurisdiction	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	3,461,203	3,620,072	3,644,582	3,707,623	3,760,259	3,606,862	3,724,741	3,722,925	3,642,667	3,639,592
ND	236,038	237,269	245,374	252,678	258,619	256,348	258,868	263,106	258,259	269,971
SD	192,126	213,030	210,845	223,795	230,651	227,655	238,201	239,165	240,964	242,783
Total Retail	3,889,367	4,070,371	4,100,801	4,184,095	4,249,529	4,090,865	4,221,810	4,225,196	4,141,890	4,152,346

Excess Demand (KW)

Jurisdiction	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	2,895,042	2,716,889	2,892,909	2,662,447	2,457,616	2,602,310	2,852,596	3,264,395	3,297,496	3,338,185
ND	161,318	182,747	187,041	203,377	137,595	139,866	154,492	153,701	176,701	153,176
SD	198,137	193,674	252,755	232,973	201,601	184,380	233,462	253,898	253,054	254,271
Total Retail	3,254,497	3,093,310	3,332,705	3,098,798	2,796,812	2,926,556	3,240,550	3,671,994	3,727,251	3,745,632

Load Factor

Jurisdiction	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	54.45%	57.13%	55.75%	58.20%	60.47%	58.09%	56.63%	53.28%	52.49%	52.16%
ND	59.40%	56.49%	56.75%	55.41%	65.27%	64.70%	62.63%	63.12%	59.38%	63.80%
SD	49.23%	52.38%	45.48%	49.00%	53.36%	55.25%	50.50%	48.51%	48.78%	48.84%
Total Retail	54.93%	59.05%	55.84%	59.42%	61.66%	60.31%	56.87%	54.16%	53.44%	52.89%

Table E-3: Coincident Peak Demand (NSPM) – Weather Normalized

1CP Demand (KW)

Jurisdiction	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	6,204,613	6,264,637	6,319,906	6,293,606	6,312,518	5,931,369	6,517,625	6,470,385	6,625,425	6,703,001
ND	339,087	378,803	312,843	375,660	392,413	311,025	331,388	318,921	385,470	373,064
SD	369,844	373,614	399,702	318,466	392,299	401,379	416,828	431,099	387,593	466,485
Total Retail	6,913,544	7,017,054	7,032,450	6,987,732	7,097,230	6,643,773	7,265,840	7,220,406	7,398,488	7,542,550

3CP Demand (KW)

Jurisdiction	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	18,054,594	18,151,069	18,436,221	18,621,758	18,554,337	17,733,505	19,071,712	19,041,505	19,342,527	19,229,251
ND	1,008,718	1,106,614	1,032,858	940,213	1,034,134	884,762	1,039,734	1,012,306	1,096,906	1,162,420
SD	1,083,556	1,091,840	1,123,995	1,051,725	1,144,136	1,092,862	1,258,131	1,262,131	1,376,938	1,336,415
Total Retail	20,146,868	20,349,524	20,593,074	20,613,696	20,732,607	19,711,128	21,369,578	21,315,942	21,816,371	21,728,087

4CP Demand (KW)

Jurisdiction	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	23,606,283	23,245,795	23,755,467	24,559,799	24,762,828	23,025,247	24,825,290	24,667,047	25,695,648	25,069,411
ND	1,317,022	1,376,868	1,400,298	1,282,333	1,363,797	1,230,516	1,386,955	1,312,531	1,454,006	1,448,205
SD	1,395,997	1,425,380	1,452,851	1,418,149	1,454,741	1,425,811	1,634,692	1,659,385	1,814,993	1,772,768
Total Retail	26,319,302	26,048,043	26,608,617	27,260,281	27,581,367	25,681,574	27,846,937	27,638,963	28,964,648	28,290,384

Sum/Win CP Demand (KW)

Jurisdiction	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	31,993,643	31,981,606	32,304,725	32,476,696	32,465,998	31,627,770	32,964,951	32,895,988	32,805,821	32,757,680
ND	2,108,698	2,191,701	2,133,967	2,088,353	2,133,192	2,018,210	2,123,168	2,097,073	2,153,088	2,321,695
SD	1,847,034	1,875,427	1,899,310	1,903,726	2,027,301	1,961,414	2,155,355	2,178,625	2,278,348	2,274,267
Total Retail	35,949,375	36,048,735	36,338,002	36,468,775	36,626,492	35,607,394	37,243,474	37,171,686	37,237,257	37,353,643

12CP Demand (KW)

Jurisdiction	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	59,867,389	60,247,577	60,582,714	61,193,984	60,561,210	58,501,075	61,683,124	60,986,071	60,936,661	60,080,171
ND	3,934,989	3,974,723	4,071,729	4,011,309	3,963,915	3,813,222	3,910,656	3,967,594	3,981,566	4,181,557
SD	3,365,087	3,485,712	3,572,112	3,665,969	3,600,046	3,577,699	3,923,492	3,979,255	4,189,678	4,192,655
Total Retail	67,167,465	67,708,012	68,226,555	68,871,262	68,125,171	65,891,996	69,517,272	68,932,921	69,107,904	68,454,383

Wtd 12CP Demand (KW)

Jurisdiction	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	73,691,923	71,268,183	75,601,822	76,567,492	77,018,390	72,903,575	78,441,816	77,766,829	79,862,117	77,722,682
ND	4,764,733	4,651,394	5,001,772	4,900,385	4,946,908	4,662,451	4,879,823	4,941,506	5,113,084	5,279,080
SD	4,158,556	4,143,992	4,479,424	4,568,753	4,579,746	4,469,023	5,008,876	5,089,661	5,508,230	5,433,928
Total Retail	82,615,212	80,063,569	85,083,018	86,036,629	86,545,044	82,035,049	88,330,516	87,797,996	90,483,431	88,435,690

36CP Demand (KW)

Jurisdiction	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	172,777,554	176,139,761	180,697,680	182,024,274	182,337,907	180,256,268	180,745,409	181,170,270	183,605,856	182,002,903
ND	11,407,465	11,691,683	11,981,441	12,057,761	12,046,953	11,788,446	11,687,793	11,691,472	11,859,815	12,130,717
SD	9,608,668	9,874,738	10,422,911	10,723,793	10,838,127	10,843,714	11,101,237	11,480,447	12,092,425	12,361,588
Total Retail	193,793,687	197,706,183	203,102,031	204,805,829	205,222,987	202,888,428	203,534,439	204,342,188	207,558,097	206,495,208

Table E-4: Miscellaneous Data for Factor Calculations – Weather Normalized

Stratification of Demand and Energy - % Split

Jurisdiction	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
% Capacity	35.73%	35.73%	34.05%	35.73%	33.56%	32.42%	35.73%	32.21%	31.29%	32.26%
% Baseload	64.27%	64.27%	65.95%	64.27%	66.44%	67.58%	64.27%	67.79%	68.71%	67.74%
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Non-Coincident Peak Demand (KW)

Jurisdiction	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	6,209,787	6,421,578	6,263,308	6,211,383	6,371,724	5,996,473	6,524,148	6,578,641	6,631,880	6,708,314
ND	413,939	451,570	455,630	492,425	401,006	402,992	441,595	434,106	447,882	417,539
SD	409,663	431,566	474,014	489,950	452,561	427,839	458,375	511,273	502,284	475,468
Total Retail	7,033,389	7,304,714	7,192,952	7,193,757	7,225,291	6,827,304	7,424,118	7,524,020	7,582,046	7,601,321

Energy (MWh)

Jurisdiction	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	31,562,334	32,156,430	32,193,794	32,609,482	32,876,888	31,974,463	32,238,155	32,255,769	31,733,088	31,421,882
ND	2,285,933	2,273,815	2,261,728	2,305,331	2,282,164	2,269,708	2,270,266	2,294,481	2,293,753	2,327,475
SD	1,803,057	1,888,070	1,931,959	2,032,112	2,017,394	2,020,813	2,071,599	2,081,821	2,088,195	2,101,341
Total Retail	35,651,325	36,318,315	36,387,481	36,946,925	37,176,446	36,264,984	36,580,021	36,632,071	36,115,035	35,850,698

Average Demand (KW)

Jurisdiction	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	3,593,162	3,670,825	3,675,091	3,722,544	3,742,815	3,650,053	3,680,155	3,682,165	3,612,601	3,586,973
ND	260,238	259,568	258,188	263,166	259,809	259,099	259,163	261,927	261,129	265,694
SD	205,266	215,533	220,543	231,976	229,667	230,686	236,484	237,651	237,727	239,879
Total Retail	4,058,666	4,145,926	4,153,822	4,217,686	4,232,291	4,139,838	4,175,801	4,181,743	4,111,457	4,092,545

Excess Demand (KW)

Jurisdiction	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	2,616,625	2,750,753	2,588,217	2,488,839	2,628,909	2,346,420	2,843,993	2,896,475	3,019,279	3,121,341
ND	153,701	192,002	197,442	229,259	141,197	143,893	182,432	172,179	186,753	151,845
SD	204,397	216,033	253,471	257,974	222,894	197,153	221,891	273,622	264,557	235,589
Total Retail	2,974,723	3,158,788	3,039,130	2,976,072	2,993,000	2,687,465	3,248,316	3,342,276	3,470,589	3,508,776

Load Factor

Jurisdiction	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	57.86%	57.16%	58.68%	59.93%	58.74%	60.87%	56.41%	55.97%	54.47%	53.47%
ND	62.87%	57.48%	56.67%	53.44%	64.79%	64.29%	58.69%	60.34%	58.30%	63.63%
SD	50.11%	49.94%	46.53%	47.35%	50.75%	53.92%	51.59%	46.48%	47.33%	50.45%
Total Retail	58.71%	59.08%	59.07%	60.36%	59.63%	62.31%	57.47%	57.92%	55.57%	54.26%

Table E-5: Coincident Peak Demand (NSPM) – Budget

1CP Demand (KW)

Jurisdiction	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	6,317,930	6,511,662	6,228,709	6,546,124	6,475,368	6,140,850	6,263,246	6,137,365	6,081,949
ND	356,961	364,867	366,424	387,634	345,408	367,493	361,938	349,916	380,893
SD	345,536	361,533	363,076	384,092	369,808	381,275	378,926	368,763	403,311
Total Retail	7,020,427	7,238,062	6,958,209	7,317,850	7,190,585	6,889,618	7,004,111	6,856,043	6,866,153

3CP Demand (KW)

Jurisdiction	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	18,760,720	19,320,330	17,931,348	19,468,352	19,380,351	18,470,681	18,827,750	18,381,911	18,430,110
ND	1,016,602	1,035,979	1,023,228	1,157,188	1,046,835	1,008,330	997,291	1,016,442	1,042,737
SD	1,103,959	1,137,702	1,152,723	1,218,890	1,175,417	1,176,325	1,206,193	1,223,466	1,283,305
Total Retail	20,881,281	21,494,011	20,107,299	21,844,429	21,602,603	20,655,336	21,031,234	20,621,818	20,756,152

4CP Demand (KW)

Jurisdiction	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	24,648,322	25,322,115	23,890,893	25,543,876	25,481,192	24,352,503	24,769,277	24,126,242	24,198,863
ND	1,344,862	1,371,924	1,366,220	1,524,927	1,402,312	1,366,930	1,353,504	1,354,943	1,417,542
SD	1,416,793	1,465,991	1,510,032	1,615,252	1,592,813	1,533,757	1,556,286	1,596,463	1,714,807
Total Retail	27,409,978	28,160,030	26,767,145	28,684,055	28,476,317	27,253,190	27,679,066	27,077,648	27,331,213

Sum/Win CP Demand (KW)

Jurisdiction	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	32,553,578	33,417,064	32,130,939	33,981,661	33,411,770	32,669,320	33,243,310	32,626,275	32,131,313
ND	2,080,398	2,117,421	2,117,592	2,291,487	2,114,631	2,162,492	2,179,654	2,163,006	2,187,097
SD	1,856,769	1,906,254	1,984,976	2,034,208	2,021,838	2,091,512	2,162,886	2,166,335	2,219,569
Total Retail	36,490,745	37,440,739	36,233,508	38,307,356	37,548,239	36,923,324	37,585,849	36,955,616	36,537,978

12CP Demand (KW)

Jurisdiction	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	60,950,771	62,524,662	61,279,515	63,655,817	62,688,657	61,328,203	62,587,113	61,311,090	60,268,610
ND	3,868,429	3,925,574	3,955,724	4,223,660	3,968,970	4,085,446	4,109,688	4,047,992	4,128,692
SD	3,346,876	3,438,810	3,586,549	3,768,336	3,851,442	3,864,822	3,945,062	3,954,652	4,114,292
Total Retail	68,166,076	69,889,046	68,821,788	71,647,813	70,509,069	69,278,471	70,641,863	69,313,734	68,511,594

Wtd 12CP Demand (KW)

Jurisdiction	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	74,926,199	77,166,368	72,670,382	76,748,687	77,675,263	75,094,648	76,185,411	75,529,610	76,958,197
ND	4,674,709	4,762,579	4,645,163	5,032,661	4,831,034	4,920,454	4,915,917	4,910,792	5,170,823
SD	4,140,587	4,272,419	4,283,157	4,574,600	4,780,598	4,735,540	4,803,209	4,891,726	5,276,050
Total Retail	83,741,495	86,201,366	81,598,702	86,355,949	87,286,895	84,750,642	85,904,537	85,332,129	87,405,071

36CP Demand (KW)

Jurisdiction	2005	2006	2007	2008	2009	2010	2011	2012	2013
MN	176,250,735	182,750,602	184,103,609	185,098,692	188,397,679	182,594,439	182,214,072	185,579,695	183,518,742
ND	11,541,611	11,685,214	11,859,386	12,220,626	12,266,631	11,880,838	11,994,295	12,068,189	12,208,043
SD	9,698,277	10,113,148	10,514,609	10,899,507	11,342,883	11,183,715	11,373,733	11,822,997	12,114,387
Total Retail	197,490,623	204,548,963	206,477,604	208,218,824	212,007,194	205,658,991	205,582,100	209,470,881	207,841,173

Table E-6: Miscellaneous Data for Factor Calculations – Budget

Stratification of Demand and Energy - % Split									
Jurisdiction	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
% Capacity	35.73%	34.05%	35.73%	33.56%	32.42%	35.73%	32.21%	31.29%	32.26%
% Baseload	64.27%	65.95%	64.27%	66.44%	67.58%	64.27%	67.79%	68.71%	67.74%
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Non-Coincident Peak Demand (KW)									
Jurisdiction	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
MN	6,421,578	6,263,308	6,211,383	6,371,724	5,996,473	6,524,148	6,578,641	6,631,880	6,708,314
ND	451,570	455,630	492,425	401,006	402,992	441,595	434,106	447,882	417,539
SD	431,566	474,014	489,950	452,561	427,839	458,375	511,273	502,284	475,468
Total Retail	7,304,714	7,192,952	7,193,757	7,225,291	6,827,304	7,424,118	7,524,020	7,582,046	7,601,321
Energy (MWh)									
Jurisdiction	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
MN	31,561,398	31,856,080	32,741,205	32,772,720	33,515,568	32,221,084	32,597,728	32,390,447	31,356,915
ND	2,119,109	2,099,310	2,143,487	2,217,924	2,317,598	2,283,855	2,322,121	2,314,121	2,335,747
SD	1,760,921	1,783,923	1,915,854	1,923,300	2,067,356	2,083,596	2,119,188	2,117,510	2,118,121
Total Retail	35,441,428	35,739,313	36,800,546	36,913,944	37,900,522	36,588,535	37,039,036	36,822,078	35,810,782
Average Demand (KW)									
Jurisdiction	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
MN	3,602,899	3,636,539	3,737,580	3,730,956	3,825,978	3,678,206	3,721,202	3,687,437	3,579,557
ND	241,907	239,647	244,690	252,496	264,566	260,714	265,082	263,447	266,638
SD	201,018	203,644	218,705	218,955	236,000	237,853	241,916	241,064	241,795
Total Retail	4,045,825	4,079,830	4,200,976	4,202,407	4,326,544	4,176,773	4,228,200	4,191,949	4,087,989
Excess Demand (KW)									
Jurisdiction	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
MN	2,818,679	2,626,769	2,473,802	2,640,768	2,170,495	2,845,942	2,857,439	2,944,443	3,128,758
ND	209,663	215,983	247,735	148,510	138,426	180,881	169,024	184,435	150,901
SD	230,548	270,370	271,245	233,606	191,839	220,522	269,356	261,220	233,674
Total Retail	3,258,889	3,113,122	2,992,782	3,022,884	2,500,760	3,247,344	3,295,819	3,390,097	3,513,332
Load Factor									
Jurisdiction	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
MN	56.11%	58.06%	60.17%	58.55%	63.80%	56.38%	56.56%	55.60%	53.36%
ND	53.57%	52.60%	49.69%	62.97%	65.65%	59.04%	61.06%	58.82%	63.86%
SD	46.58%	42.96%	44.64%	48.38%	55.16%	51.89%	47.32%	47.99%	50.85%
Total Retail	57.63%	56.37%	60.37%	57.43%	60.17%	60.62%	60.37%	61.14%	59.54%

CAMBRIDGE
NEW YORK
SAN FRANCISCO
WASHINGTON
LONDON
MADRID
ROME

THE Brattle GROUP