Minnesota Public Utilities Commission

Staff Briefing Papers – Volume VI of VII
Rate Design

Meeting Date:	**March 19, 2015 (Oral Argument)**	**Agenda Item # ___**
	March 26, 2015 (Deliberations)	

Company: Xcel Energy (Xcel or the Company)

Docket No. **E002/M-13-867**

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

Issues: **Rate Design**

Staff: Andrew Twite .... (651) 201-2245
Susan Mackenzie .... (651) 201-2241

Table of Contents

Rate Design Introduction

In a rate case, ratemaking is a two-step process: the Commission first establishes the revenue requirement, acting in its quasi-judicial function as a factfinder; in the second step, rate design, the Commission determines how recovery of the revenue requirement is allocated between classes and how rates are structured within classes.[1] In this step, the Commission exercises its legislative function, which requires "balancing both cost and non-cost factors and making choices among public policy alternatives" to determine the apportionment and rate structure that is most consistent with the public interest.[2]

In designing rates, the Commission has considered a wide variety of factors, such as:

- The utility's ability to collect its legitimate costs;
- Promotion of revenue stability for the utility;
- Recovery of reasonable amounts of economic development expenses[3];
- Ease of administration;
- Cost of serving the customer classes;
- Customers' ability to pay[4];
- Customers' ability to pass along increases;
- Customers' ability to deduct utility expenses on taxes;
- Customers' ability to bypass the utility;
- Continuity with prior rates, in order to avoid rate shock or rate destabilization;
- Ease of understandability;
- Encouragement of renewable energy[5];
- Encouragement of energy conservation[6]; and
- Encouragement of cogeneration and small power production.[7]

Overall, the Commission has considerable authority to exercise its judgment, provided the final rates are "just and reasonable" and not "unreasonably preferential, unreasonably prejudicial, or discriminatory."[8]

[1] *Hibbing Taconite Co. v. Minnesota Pub. Serv. Comm'n*, 302 N.W.2d 5 (Minn. 1980), at page 9.
[2] *St. Paul Area Chamber of Commerce v. Minnesota Pub. Serv. Comm'n*, 251 N.W.2d 350 (Minn. 1977) at page 358.
[3] See Minn. Stat. § 216B.16, subd. 13.
[4] Ibid, at subd. 15.
[5] See Minn. Stat. § 216B.03.
[6] See Minn. Stat. §§ 216B.03, 216B.2401.
[7] See Minn. Stat. §§ 216B.03, 216B.164.
[8] Minn. Stat. § 216B.03.

Class Revenue Apportionment

PUC Staff: Andrew Twite

Statement of the Issues

What apportionment of class revenue responsibility should the Commission adopt?

How should changes such as a revised forecast, revenue requirement and CCOSS be reflected in the final class revenue apportionment?

Introduction

Once it has established the appropriate revenue requirement, the Commission must next determine what portion of the revenue requirement should be recovered from each class. This process is referred to as class revenue apportionment. As described above, in this process the Commission acts in its legislative capacity, making choices among policy alternatives to determine the apportionment that is most in keeping with the broader public interest.

In this case, several parties proposed class revenue apportionments. All parties begin their analyses with a consideration of their preferred Class Cost of Service Study (CCOSS). Some—like the Minnesota Chamber of Commerce and Xcel Large Industrials—conclude that class revenues should be apportioned strictly according to CCOSS cost estimates. Others—like Xcel, the Administrative Law Judge, the Department of Commerce and the Office of the Attorney General—argue that non-cost factors necessitate an apportionment that diverges from CCOSS cost estimates. In the end, these six parties recommended six different class revenue apportionments, which are summarized in Staff Table 1 below.[9] The table depicts the rate increase for each class that would result from the party's apportionment. Commissioners should note, however, that these percentages will change according to the final revenue requirement; Staff presents them to provide a sense of how the parties' proposals compare with each other.

Staff Table 1, Allocation of Rate Increases by Party (According to Xcel's Initial Revenue Requirement Request)

Class	ALJ	Xcel	DOC	OAG	MCC	XLI
2014—Test Year						
Residential	6.4%	7.6%	6.4%	6.2%	10.1%	7.8%
Non-Demand	4.8%	7.7%	4.8%	6.2%	7.8%	6.6%
C&I Demand	6.3%	5.4%	6.3%	6.3%	4.2%	5.3%
Lighting	0%	0%	0%	0%	-13%	0%
2015—Step Year (cumulative increase over 2 years)						
Residential	9.9%	11.3%	9.9%	9.7%	-	-
Non-Demand	8.4%	11.2%	8.2%	9.7%	-	-
C&I Demand	9.8%	8.9%	9.8%	9.8%	-	-
Lighting	0%	0%	3.1%	2.9%	-	-

[9] Source: Xcel Energy, Initial Brief, Table 4: "Comparison of Recommended Allocations of Proposed Revenue Increase," at page 139. The ALJ's recommended apportionment was added by Staff. Staff has also altered Xcel's figures for the OAG in 2015; Staff believes this allocation more accurately reflects the OAG's apportionment methodology. As the Company notes, the MCC and XLI did not provide specific allocations for 2015.

This section begins with a summary of each party's class revenue apportionment recommendation, including its proposal and the rationale underlying it. These are followed by a summary of parties' opinions on how the apportionment should be updated if the Commission makes revisions to the Company's revenue requirement and/or CCOSS.

Party Positions

Xcel Energy

Xcel's revenue apportionment approach is primarily cost-based, with some modification for non-cost factors. The Company begins with the class cost estimates produced by its CCOSS.[10] In Xcel's words: "The cost of service is the appropriate and objective starting point for the apportionment process because cost-based rates promote efficient use of resources and improve equity across classes by reducing subsidization between customer classes."[11]

However, the Company argues that a move completely to cost would be inappropriate, as the benefits of cost-based apportionment need to be balanced against non-cost factors. A 4.58% rate increase for the residential class went into effect in December 2013, so a moderated movement to cost will help maintain rate continuity. Further, the Company refined its CCOSS methodology for this rate case, so the moderated movement to cost will allow these changes to be implemented gradually. In addition, the Company cited the MCC and XLI's arguments about the competitiveness of its C&I demand rates and the sensitivity of these customers to changes in operating cost; thus, the Company argues it is important to moderate the rate increase for the C&I Demand class.

Xcel's class revenue apportionment proposal is presented in the "proposed revenue" column of Staff Table 2, below. A comparison with the "cost of service" column shows no class is moved exactly to Xcel's cost estimates; this reflects the Company's belief that the movement to cost should be moderated to reach an appropriate balance between cost and non-cost factors.

<u>Staff Comment</u>

Staff believes the apportionment recommended by Xcel does not follow from the methodology laid out in Exhibit 107 (Huso Rebuttal), which stated:

- Move both the Residential and C&I Non-Demand classes 75 percent closer to the Company's estimate of cost;
- Maintain the current level of Lighting class revenues; and
- Recover the remaining revenue requirement from the C&I Demand class.[12]

As Staff Table 2 below shows, in Xcel's rebuttal testimony, its proposed apportionments for 2014 and 2015 are considerably closer to cost than if the Company had followed its proposed methodology. Xcel's proposed apportionment moves the Residential class 94.3% and 95.7%

[10] The Company made slight modifications to both its CCOSS and its revenue apportionment in its Rebuttal testimony. Here, Staff only presents the updated estimates and apportionments.
[11] Exhibit 107 (Huso Rebuttal), at page 9.
[12] At page 3, as modified on page 5.

closer to the Company's estimate of cost in 2014 and 2015, respectively; for C&I Non-demand the increase is 94% and 95.8%.[13] Had these totals been moved 75 percent closer to cost, as Xcel's methodology recommended, these classes would have been allocated over $43 million less over the two years.

Staff Table 2. Xcel Proposed Class Revenue Apportionment (in millions)

Class	Present Revenue	Cost of Service	Proposed Revenue	Rebuttal Methodology	Difference
			2014—Test Year		
Residential	$983.3	$1,062.4	$1,057.9	$1,042.6	$15.3
Non-Demand	$101.4	$109.7	$109.2	$107.6	$1.6
C&I Demand	$1,603.5	$1,687.3	$1,690.1	$1,706.9	-$16.8
Lighting	$25.8	$23.5	$25.8	$25.8	$0
Total	$2,713.8	$2,882.9	$2,882.9	$2,882.9	
			2015—Step Year		
Residential	$983.3	$1,099.0	$1,094	$1,070.1	$23.9
Non-Demand	$101.4	$113.2	$112.7	$110.3	$2.5
C&I Demand	$1,603.5	$1,740.6	$1,745.4	$1,771.7	-$26.3
Lighting	$25.8	$25.0	$25.8	$25.8	$0
Total	$2,713.8	$2,977.8	$2,977.8	$2,977.8	

Department of Commerce (the Department)

The foundation for the Department's class revenue allocation is its CCOSS, which makes several adjustments to Xcel's CCOSS. The Department favors a cost-based foundation for several reasons:

> Certainly, rates should be fair, and ideally the best way to define "fair" is that each class of customer would pay enough to cover its share of costs. Moreover, customers need accurate information about the cost of electricity so they can make informed decisions about how much electricity they use. This information is often called "price signals." For example, if customers are informed through their rates that electricity is less expensive than the actual cost of electricity, customers would not have the appropriate incentive to reduce their use of electricity.[14]

However, the Department does not recommend that rate increases be moved fully to cost. The Department notes that cost allocations are not perfect: "there is often more than one way to allocate costs to customer classes. Moreover, even if cost allocations were perfect, apportioning revenue responsibility should also avoid rate shock."[15] Thus, the Department's apportionment aims to move all classes closer to its estimate of costs while tempering the impact to customers' bills.

In direct testimony, the Department laid out the following apportionment methodology:

- For 2014

---

[13] Calculation: (Proposed revenue – present revenue) / (Cost of service – present revenue).
[14] Exhibit 420 (Peirce Direct), at page 10.
[15] Ibid, at page 11.

  - Maintain the current level of Lighting class revenue;
  - Move the C&I Demand class to the Department's estimate of cost;
  - Move the C&I Non-Demand class to just over cost; and
  - Move the Residential class to just under cost.
- For 2015
  - Apply the percentage of total revenue apportioned to each class in 2014 to Xcel's proposed 2015 revenue requirement.

Following Xcel's revision of its estimates of current costs and revenue requirements in Rebuttal testimony, the Department adjusted its recommended revenue apportionment in its Surrebuttal Testimony. The Department's final apportionment recommendation is provided in the tables below.[16] The Department adjusted its initial proposal according to a formula that will be discussed in detail in the "Revenue Apportionment Adjustment Process" section on pages 14 to 15 below.

Table 6: Summary of DOC's Updated Proposed 2014 Apportionment of Revenue Responsibility (in thousands)

Customer Class	Revised Current Revenue	Xcel Proposed 2014 Revenue-Revised	Percent Increase	DOC Proposed Revenue	Percent of Total Revenue	Percent Increase
Residential	$983,255	$1,057,900	7.6%	$1,046,247	36.3%	6.4%
C&I Non-Demand	$101,372	$109,200	7.7%	$106,229	3.7%	4.8%
C&I Demand	$1,603,456	$1,690,100	5.4%	$1,705,070	59.1%	6.3%
Lighting	$25,753	$25,800	0.2%	$25,753	0.9%	0.0%
Total	$2,713,836	$2,883,299	6.2%	$2,883,299	100.0%	6.2%

Table 7: Summary of DOC's Updated Proposed 2015 Apportionment of Revenue Responsibility (in thousands)

Customer Class	Revised Current Revenue ($1,000's)	Xcel Proposed 2015 Revenue	DOC Proposed Revenue	Percent of Total Revenue	Percent Increase Current	% change from 2014
Residential	$983,255	$1,094,000	$1,080,588	36.3%	9.9%	3.3%
C&I Non-Demand	$101,372	$112,700	$109,664	3.7%	8.2%	3.2%
C&I Demand	$1,603,456	$1,745,400	$1,761,002	59.1%	9.8%	3.3%
Lighting	$25,753	$25,800	$26,546	0.9%	3.1%	3.1%
Total	$2,713,836	$2,977,800	$2,977,800	100.0%	9.7%	3.3%

Office of the Attorney General (OAG)

Like the Department, the OAG also recommends several adjustments to Xcel's proposed CCOSS. The OAG's preferred CCOSS for 2014 and 2015 is displayed in the table below.[17] As the OAG notes, under Xcel's initial estimates the current apportionment is relatively close to the OAG's CCOSS estimate, with the exception of the lighting class.

[16] Source: Department of Commerce, Initial Brief, September 23, 2014, at page 288.
[17] Source: Exhibit 375 (Nelson Direct), Table 8 Comparison of Current Revenue Apportionment and 2014 and 2015 Cost Responsibility, at page 38.

Class	(a) Current Apportionment	(b) 2014 Cost	(c) 2015 Cost	(a)-(b) 2014 Cost Difference	(a)-(c) 2015 Cost Difference
Residential	35.91%	36.02%	35.72%	-0.11%	0.19%
C&I Non-Demand	3.78%	3.75%	3.72%	0.03%	0.06%
C&I Demand	59.36%	59.39%	59.68%	-0.03%	-0.32%
Lighting	0.95%	0.83%	0.87%	0.12%	0.08%

While the OAG believes its adjustments improve the CCOSS, the OAG argues that even this improved CCOSS is imperfect and should not be the primary foundation for class revenue apportionment. In the OAG's words:

> [P]ricing at the marginal cost of the next unit of electricity consumed results in the most efficient use of resources. The CCOSS is often used to inform efficient pricing. However, the CCOSS estimates average cost, not the marginal cost. These two costs are not likely equal to each other, which presents the problem of determining the most efficient rate design. The other issue is that the precision of the average cost estimated by the CCOSS is not measured, meaning there is no estimation of error associated with the model. How should decision-makers deal with the uncertainty of the CCOSS when setting rates? The OAG suggests that the most reasonable way to deal with the uncertainty involved with measuring marginal and average costs is to put more emphasis on [rate shock & non-cost factors].[18]

Accordingly, the OAG's apportionment methodology does not track its CCOSS as other parties' methodologies do. Instead, the OAG laid out the following methodology for 2014:

- Maintain the current level of lighting revenue;
- Increase the Residential and C&I non-Demand classes in proportionate to Xcel's stated 2014 deficiency percentage;
- Recover the remaining revenue requirement from the C&I Demand class.

The methodology was the same for 2015, with one exception: rather than setting the Lighting class at its current revenue, the OAG uses the estimate from its CCOSS. Staff's tables below summarize the OAG's preferred class revenue apportionment.[19]

[18] Ibid., at pages 34-35.
[19] Though the OAG updated its CCOSS in Exhibit 378 (Nelson Surrebuttal), it did not update its class revenue apportionment calculation. These tables are Staff's adaptation of Tables 9 and 10 from Exhibit 375 (Nelson Direct), at page 39.

Staff Table 3. OAG Recommended 2014 Test Year Revenue Apportionment ($ in 000's)

Class	(a) Present Revenue	(b) Cost of Service (OAG)	((b)/(a))-1 Cost Increase	(c) Proposed Revenue	(d) % of total Revenues	((c)/(a))-1 Proposed Increase	(c)-(b) Proposed Cost Difference
Residential	$983,255	$1,032,625	5.02%	$1,044,635	36.23%	6.24%	$12,028
Non-Demand	$101,372	$107,622	6.17%	$107,702	3.74%	6.24%	$80
C&I Demand	$1,603,456	$1,718,073	7.15%	$1,705,190	59.14%	6.34%	-$12,883
Lighting	$25,753	$24,978	-3.01%	$25,753	0.89%	0%	$775
Total	$2,713,836	$2,883,298	6.24%	$2,883,299	100%	6.24%	

Staff Table 4. OAG Recommended 2015 Step Year Revenue Apportionment ($ in 000's)

Class	(a) Present Revenue	(b) Cost of Service (OAG)	((b)/(a))-1 Cost Increase	(c) Proposed Revenue	(d) % of total Revenues	((c)/(a))-1 Proposed Increase	(c)-(b) Proposed Cost Difference
Residential	$983,255	$1,068,295	8.65%	$1,078,892	36.23%	9.73%	$10,597
Non-Demand	$101,372	$111,034	9.53%	$111,232	3.74%	9.73%	$198
C&I Demand	$1,603,456	$1,771,981	10.51%	$1,761,186	59.14%	9.84%	-$10,795
Lighting	$25,753	$26,490	2.86%	$26,490	0.89%	2.86%	$0
Total	$2,713,836	$2,978,355	9.73%	$2,977,800	100%	9.73%	

Minnesota Chamber of Commerce (MCC)

The MCC argues that Xcel's business and industrial rates are too high, which has a negative impact not only on these customers, but also on all of Xcel's ratepayers and Minnesota's economy as a whole. The MCC notes that Xcel's rates are higher than both Minnesota's other IOUs and the IOUs in North and South Dakota. With more attractive rates elsewhere, the MCC argues that Xcel's business customers may move or shift production to out-of-state facilities; in the MCC's words:

> The proposed rate increases have the potential to adversely impact the economic activity and competitiveness of our members and pose significant challenges for customers who cannot pass costs to downstream markets due to highly competitive business conditions or who are not expanding and able to offset the increased costs through increased production or output.[20]

And as businesses move, shift production elsewhere, or self-generate, all of Xcel's remaining customers face the risk of rate increases.

[20] Exhibit 343 (Maini Direct), at page 30.

The MCC argues that these non-cost factors support commercial and industrial rates being set at cost. The MCC makes several recommendations for improvements to Xcel's CCOSS. But, regardless of what form the final Commission-approved CCOSS takes, MCC argues that cost should be the starting point for determining class revenue apportionment. As the MCC put it, "If the CCOSS has been performed correctly, then the output of the CCOSS should reflect accurate class allocation. Significant deviation from CCOSS-based apportionment for non-cost factors results in some customer classes subsidizing others."[21] If for the 2014 test year the Commission decides to deviate from the costs estimated by its chosen CCOSS, the MCC urges it to move the apportionment fully to cost in 2015.

Xcel Large Industrials (XLI)

Like the MCC, XLI argues that Xcel's commercial and industrial rates are uncompetitive. XLI notes that Xcel's rates for large industrials are the highest of the IOUs in MN and are above average relative to IOUs in surrounding states and across the country. According to XLI, this results in "a continued loss of sales and an absence of significant load growth."[22] Moreover, according to XLI, large C&I demand customers "have no more of an ability to pay than any other class."[23]

XLI argues that the Commission's final class revenue apportionment should be driven solely by its approved CCOSS, without considering any non-cost factors. As XLI put it, "rates should reflect the actual costs of providing service as closely as practicable because cost based rates are equitable, provide appropriate price signals for all customer classes, encourage conservation and efficiency, and address the very serious and real problem that NSP's industrial rates are not competitive."[24]

Administrative Law Judge (ALJ) Report

The ALJ's Report discusses revenue apportionment in paragraphs 758-777. It begins with a brief discussion of the relationship between revenue apportionment and the CCOSS:

> 760. Ideally, revenue apportionment for the customer classes would match the cost allocations by class identified in the CCOSS. Moving classes closer to cost is consistent with the rate design principle that rates should promote the efficient use of resources and minimize subsidies among classes. Deviation from CCOSS-based apportionment for non-cost factors results in some customer classes subsidizing others. An inter-class subsidy occurs when the revenue responsibility apportioned to a class of customers fails to recover the cost of serving those customers, and the difference is made up by over-recovering costs from other customer classes. Minimizing inter-class subsidies is perceived to be "fair" to all ratepayers, and it gives customers accurate information (or "price signals") about the cost of electricity. If customers believe that electricity is less expensive than

[21] Minnesota Chamber of Commerce, Initial Brief, September 23, 2014, at page 22.
[22] Exhibit 260 (Pollock Direct), at page 40.
[23] Ibid, at page 38.
[24] Exhibit 263 (Pollock Surrebuttal), at page 31.

> its actual cost, they may not have the appropriate incentive to reduce their energy use.
>
> 761. However, cost allocations are not absolutely precise because there is often more than one method that may be employed to allocate costs to customer classes. Moreover, rates may need to be modified to comply with the rate design principle that rate changes should be gradual to avoid rate shock.[25]

After summarizing parties' positions, the Report provides its revenue apportionment recommendation:

> 775. Because the Administrative Law Judge has recommended that the Commission adopt what is largely the Department's proposed CCOSS methodology, the Administrative Law Judge concludes that the Department's proposed revenue apportionments for 2014 and 2015 should be adopted but modified for the Lighting Class in 2015. The Department's proposed revenue apportionments are reasonable because they are closely aligned with the costs determined by the Department's CCOSS and also avoid rate shock. As such, they properly balance the rate design principles of promoting efficient use of resources and ensuring that rate changes are gradual.
>
> 776. The Department's proposed 2015 revenue apportionment should be modified, however, to exclude any increase for the Lighting Class in 2015. As shown above in Table 17, the Department has proposed no increase for the Lighting Class in 2014; the same should be done in 2015. Otherwise, the Lighting Class will be paying a fair amount above its cost in 2015. To avoid this result, the Administrative Law Judge recommends that the increase in revenue that would have been attributable to the Lighting Class in 2015 be spread equally among the other classes. [26]

Exceptions to the ALJ Report

Xcel Energy

In its Exceptions, the Company argues that the ALJ's preference for the Department's measurement of costs in the CCOSS does not necessarily mean the ALJ should also support the Department's revenue apportionment. Revenue apportionment is a separate process, necessitating a balancing of various interests and policy objectives. The Company notes that the ALJ's recommended revenue apportionment would essentially maintain the current percentage of total revenues paid by each class.[27] The Company maintains that the Commission should give greater consideration to the importance of lowering rates for business customers.

---

[25] ALJ Report, December 26, 2014, at pages 172-173. Footnotes omitted.

[26] Ibid, at pages 176-177. Footnotes omitted.

[27] Staff notes the ALJ's 2015 apportionment in Table 1 of Xcel's Exceptions does not correspond to the calculations in the compliance filing Xcel cites. In 2015, the ALJ's recommendation would apportion revenue as follows: Residential, 36.50%; C&I Non-Demand, 3.81%; C&I Demand, 58.81%; Lighting, 0.88%.

The Company noted that it still recommends the revenue apportionment provided in Exhibit 107 (Huso Rebuttal). However, in its Exceptions, the Company proposed the following alternative, which would blend the Company's and the Department's recommendations. Staff Table 5[28] below presents a comparison of the ALJ's proposal and Xcel's alternate proposal; as the table displays, Xcel's alternative would increase revenues from the Residential and C&I non-demand classes by roughly $8.7 million over the two years and decrease revenues from the C&I Demand class by the same amount.

Staff Table 5. Xcel's Alternative Revenue Apportionment Proposal

	ALJ		Xcel (Alternative)		Xcel - ALJ
Class	(000s)	Percent	(000s)	Percent	($000s)
			2014—Test Year		
Residential	$1,023,738	36.49%	$1,026,152	36.57%	$2,414
Non-demand	$107,331	3.83%	$107,963	3.85%	$632
C&I Demand	$1,648,978	58.77%	$1,645,931	58.66%	-$3,047
Lighting	$25,814	0.92%	$25,814	0.92%	$0
Total	$2,805,861	100%	$2,805,861	100%	
			2015—Step Year		
Residential	$1,068,764	36.50%	$1,073,506	36.66%	$4,742
Non-demand	$111,646	3.81%	$112,590	3.84%	$944
C&I Demand	$1,722,031	58.81%	$1,716,345	58.61%	-$5,686
Lighting	$25,812	0.88%	$25,812	0.88%	$0
Total	$2,928,253	100%	$2,928,253	100%	

The Company also proposed modifications to ALJ Report Finding 775, which can be found on pages 36 and 37 of its Exceptions.

Office of the Attorney General (OAG) and Xcel Large Industrials (XLI)

Two other parties, OAG and XLI, commented on revenue apportionment in their respective Exceptions. However, because these comments restate the positions summarized in the party positions section above, Staff does not repeat them here. The OAG's comments can be found on pages 25-28 of its Exceptions, with its modifications to the ALJ Report Findings 775 and 776 on page 28. XLI's can be found on pages 19-21 of its Exceptions.

Revenue Apportionment Adjustment Process

Three parties made recommendations for how the class revenue apportionment should be adjusted in the final rate compliance filing if the Commission makes changes to the Company's proposed revenue requirement and/or CCOSS.[29] Two of these parties—Xcel and the Department—support a proportional adjustment to the proposed class increases, and the other—

[28] This table uses the ALJ's recommended revenue requirement, as calculated in Xcel Energy's January 16, 2015 Compliance Filing, Attachment K Page 9 of 10.

[29] From the OAG's testimony, Staff infers that the OAG would support retaining the current apportionment regardless of any possible adjustments to the revenue requirement or CCOSS. Similarly, the MCC's and the Commercial Group's testimonies suggest they would support an apportionment set according to the Commission's approved CCOSS. However, because these parties did not directly address the issue of whether or not the CCOSS should be rerun, Staff excludes them from this section.

XLI—recommends requiring Xcel to rerun the CCOSS according to the Commission's adjustments. In its report, the ALJ recommends Xcel's and the Department's approach.[30]

Xcel and the Department argue a proportional adjustment approach should be taken if the Commission makes changes to the Company's proposed revenue requirement and/or CCOSS. The formula, which has been used by the Commission in previous Xcel rate cases, is:

$$Current\ Revenues\ \times (\ 1 + Initial\ Proposed\ Increase\ (in\ \%) \times \frac{Approved\ Rev.Increase}{Initial\ Proposed\ Rev.Increase}\ )$$

Xcel provides an example of this calculation in Exhibit 105 (Huso Direct)[31]:

Proportional Apportionment Calculation Example

Class	(a) Present Revenues	(b) Proposed Increase	(c) Adjustment Factor	(a*(1+(b*c)) Final Revenues	Final Rate Increase
Residential	$55.00	12.0%	.80	$60.28	9.60%
Non-Demand	$3.00	8.0%	.80	$3.19	6.33%
C&I Demand	$40.00	7.4%	.80	$42.37	5.93%
Lighting	$2.00	10.0%	.80	$2.16	8.00%
Total	$100.00	10.0%		$108.00	8.00%

XLI, on the other hand, does not support a proportionate adjustment. In XLI's words:

> If the Commission approves a lower revenue increase and/or changes in the CCOSS, the CCOSS should be rerun at the lower revenue level reflecting all of the Commission's approved revenue requirement and cost allocation methodology. This is necessary because the revenue-to-cost relationships will necessarily change depending on the nature of any adjustments to NSP's revenue requirements and changes in allocations. The Commission-approved CCOSS can then be used to determine class revenue allocation in NSP's compliance filing following the Commission's final order. [32]

Staff Comment

Staff believes the record demonstrates that the Department's and Xcel's adjustment methodology is problematic. The adjustment formula is intended to update an apportionment when the revenue requirement is adjusted, with the goal of maintaining the original relationship between classes. In this case, however, the formula has altered the Department's apportionment method considerably, shifting cost recovery from C&I demand customers to Residential and C&I non-demand customers. As shown below, the cause of the alteration is the formula's focus on the proposed *rate increase* by class rather than the proposed *apportionment*.

---

[30] ALJ Report, December 26, 2014, ¶ 777, at page 177.

[31] Table 7, at page 13. The "Adjustment Factor" is the Commission-approved revenue increase divided by the Company's requested revenue increase.

[32] Exhibit 260 (Pollock Direct), at page 47.

In Xcel's Rebuttal testimony, the Company changed not only the overall revenue requirement, but also its estimates of current revenues by class. Current revenues were again changed in Xcel's January 16, 2015 compliance filing. As Staff Table 6 below displays, Xcel's updated estimates change both the total revenue estimate and the percentage each class contributed, with the biggest changes made to the Residential and C&I Demand classes.

Staff Table 6. Xcel's Current Revenue Estimate Changes

	Initial		Rebuttal		January 16, 2015 Compliance Filing	
Class	($000s)	Percent	($000s)	Percent	($000s)	Percent
Residential	$1,001,398	35.91%	$983,255	36.23%	$997,700	36.46%
Non-demand	$105,523	3.78%	$101,372	3.74%	$105,277	3.85%
C&I Demand	$1,655,346	59.36%	$1,603,456	59.08%	$1,607,483	58.75%
Lighting	$26,477	0.95%	$25,753	0.95%	$25,814	0.94%
Total	$2,788,744	100%	$2,713,836	100%	$2,736,274	100%

These changes significantly alter the class revenue apportionment proposed by the Department. In the adjustment methodology formula above, the Department's apportionment is reflected in its initial proposed rate increase: the Department used its CCOSS estimates as a benchmark for its apportionment, which was then used to calculate the percent rate increase for each class. However, this proposed rate increase was a function not only of the Department's apportionment, *but also Xcel's initial revenue estimates*. The formula for percent rate increase by class is as follows:

$$Class\ \%\ increase = \frac{Initial\ Proposed\ Revenues - Initial\ Current\ Revenue\ Estimate}{Initial\ Current\ Revenue\ Estimate}$$

Because the Department's proposed percent increases by class were determined by both its CCOSS *and* the initial current revenue estimates, the updated current revenue figures in Staff Table 6 above change the Department's proposed apportionment considerably, to the point where it is no longer in line with the Department's initial apportionment:

Staff Table 7. Department Proposed 2014 and 2015 Revenue Apportionments

	Department CCOSS	Initial Proposal	Surrebuttal Proposal	Final Proposal
Residential	36.06%	35.97%	36.29%	36.49%
Non-demand	3.70%	3.73%	3.68%	3.83%
C&I Demand	59.39%	59.42%	59.14%	58.77%
Lighting	0.86%	0.89%	0.89%	0.92%

As Staff Table 7 displays, the adjustment formula alters the Department's class revenue apportionments considerably: in its initial proposal, the Department set Residential class revenue responsibility slightly below its CCOSS cost estimate and the C&I demand class slightly above its CCOSS estimate; in the final proposal, however, the adjustment formula has reversed this relationship, with the Residential class allocated *more* than the Department's CCOSS estimate and the C&I Demand class allocated *less*. And while the difference may seem small in percentage points, when converted to dollars the difference is considerable: if the Department's final allocation proposal had recovered revenues using the same proportions by class as its initial proposal, the Residential and C&I non-demand classes would be assigned over $35 million less over the two years, and the C&I demand class would be assigned nearly $36 million more.

If the Commission finds this adjustment formula unsuitable, Staff identifies an alternative formula for adjusting the final revenue apportionment. With this approach, the class allocations (as a percentage of total revenues) would simply be multiplied by the final revenue requirement. Staff Table 8 provides an adjustment of the Department's 2014 apportionment as an example. Here, the Department's initial apportionment[33] is converted to a percentage by dividing each class's apportionment by the total. These percentages are then multiplied by the updated revenue requirement[34] to produce the final apportionment. As the final column shows, the between-class apportionment relationship is maintained.

Staff Table 8. Class Revenue Apportionment Adjustment Example

	Initial Department Allocation			ALJ's Rev.		Final Allocation	
Class	(000s)	Percent		Requirement		(000s)	Percent
Residential	$1,072,268	35.97%	x	$2,805,861	=	$1,009,246	35.97%
Non-demand	$111,107	3.73%	x	$2,805,861	=	$104,577	3.73%
C&I Demand	$1,771,220	59.42%	x	$2,805,861	=	$1,667,117	59.42%
Lighting	$26,477	0.89%	x	$2,805,861	=	$24,921	0.89%
Total	$2,981,072	100.00%				$2,805,861	100.00%

In this case, the Commission would still have the option of either developing its own apportionment or selecting one of the party's recommendations described above. For example, the Commission could simply choose to apply the class percentages from the Department's initial proposal to the final revenue requirement. This approach retains the general spirit of the Department's and Xcel's adjustment formula while avoiding its unintended alterations. This proposal is included as Decision Alternative 10 below.

Class Revenue Apportionment Decision Alternatives

Apportionment

1. Adopt the ALJ's recommendation to use the Department's recommended class revenue apportionment with the modifications described in paragraph 776 of the ALJ's Report. (ALJ)

2. Reject the ALJ's recommendation and adopt Xcel's recommended class revenue apportionment as set forth in its Rebuttal testimony. (Xcel)

3. Reject the ALJ's recommendation and adopt Xcel's alternative class revenue apportionment as set forth in its Exceptions. (Xcel alternate)

[33] Exhibit 420 (Peirce Direct), at page 8.
[34] Here Staff used the ALJ's proposed revenue requirement, as reported in Xcel Energy's January 16, 2015.

4. Modify Finding 775 of the ALJ Report as proposed on pages 36 and 37 of Xcel's Exceptions to the ALJ's Report. (Xcel)

5. Reject the ALJ's recommendation and adopt the Department's recommended class revenue apportionment as set forth in its Surrebuttal testimony. (The Department)

6. Reject the ALJ's recommendation and adopt the OAG's proposal to proportionally increase revenues as set forth in Exhibit 375 (Nelson Direct). (OAG)

7. Modify Findings 775 and 776 of the ALJ Report as proposed on pages 27 and 28 of the OAG's Exceptions to the ALJ's Report. (OAG)

8. Reject the ALJ's recommendation and require Xcel to rerun the CCOSS according to the Commission's final specifications. Set class revenue responsibility to match the cost of service for that class as determined by the Commission-approved CCOSS. (MCC, XLI)

Revenue Apportionment Adjustment Calculation

9. If the Commission alters Xcel's requested revenue requirement, adjust the class revenue apportionment using the formula described in Exhibit 105 (Huso Direct). (ALJ, Department, Xcel)

10. If the Commission alters Xcel's requested revenue requirement, adjust the class revenue apportionment using the formula described in Staff's comment on page 17. (Staff adjustment alternative)

(Note: These decision alternatives correspond to alternatives II, A (1 through 8) and II, B (1 and 2) on p. 34 of the deliberation outline.)

Residential and Small General Service Customer Charges

PUC Staff: Andrew Twite

Statement of the Issue

What level of customer charge should the Commission adopt for Residential and Small General Service customers?

Introduction

Xcel's Residential and Small General Service customers currently pay both a volumetric (per-kWh) energy charge and a monthly customer charge, which does not vary by usage. This section focuses on the latter.

Staff Table 9 below summarizes the parties' preferred levels for Residential and Small General Service customer charges. The ALJ, AARP, CEI, ECC, and the OAG support maintaining the current customer charges. The Department proposes a $0.50 increase for each service category, and Xcel proposes an increase of $1.25 for Residential and $1.50 for Small General Service customers.

Staff Table 9, Preferred Customer Charges

Service Category	Current Charge	ALJ, AARP, CEI, ECC, and OAG	Department	Xcel
Residential Standard – Overhead	$8.00	$8.00	$8.50	$9.25
Residential Standard – Underground	$10.00	$10.00	$10.50	$11.25
Residential Electric Heating-Overhead	$10.00	$10.00	$10.50	$11.25
Residential Electric Heating-Underground	$12.00	$12.00	$12.50	$13.25
Small General Service	$10.00	$10.00	$10.50	$11.50

Parties made several arguments as to why the customer charge should or should not be increased, with many parties making similar points. To avoid redundancy, Staff has organized comments not by party, but by sub-issue. Issues considered include: intra-class equity; the calculation of fixed costs; the effect of a customer charge increase on conservation incentives; the potential impact of revenue decoupling; the impact of an increase on low-income and/or elderly customers; the potential for rate shock; and Commission precedent.

Issue summaries

Intra-class cross subsidy

As Xcel notes, the balance between fixed charges and energy charges is a zero-sum exchange: if a portion of the fixed costs is not collected in customer charges, it must be collected through energy charges, and vice versa. This presents the possibility for intra-class cross subsidy: if the customer charge is set below the level of average fixed costs, customers with above-average usage will in effect subsidize customers with below-average usage, because the energy charge must collect not only the variable energy costs, but also the remaining portion of the fixed costs. The utility will still recover all of its costs, but customers with above-average consumption will pay more than their cost of service. Similarly, if the customer charge is set above fixed costs, customers with below-average consumption will be subsidizing those with above-average consumption.

Xcel calculates[35] its per-customer fixed costs are $15.70 per-month for Residential customers and $16.65 for Small General Service customers.[36] Using Xcel's calculation of costs, customer charges fall below the fixed cost of service by $6.98 (weighted average) and $6.65 for Residential and Small General Service customers, respectively. Because the balance between fixed and usage charges is a zero-sum exchange, Xcel argues that at current levels the customer charges present an intra-class subsidy in which high-use customers are subsidizing lower-use customers. To moderate this subsidy, Xcel proposes a per-month increase in customer charges of $1.25 for all Residential classes and $1.50 for the Small General Service class.

The Department's customer charge analysis relies on Xcel's calculation of the customer costs. Accordingly, the Department agrees with Xcel that an increase in customer charges is necessary to reduce intra-class subsidies. However, the Department notes that Xcel has recently raised its customer charges, and that Xcel's proposed increase would make its customer charges significantly higher than the state's other IOUs. In order to balance concerns about rate shock and inter-utility customer equity with intra-class subsidy, the Department recommends a 50 cent increase in customer charges for both Residential and Small General Service customers.

Two parties—the Energy CENTS Coalition (ECC) and the Clean Energy Interveners (CEI)—took issue with Xcel's and the Department's position on intra-class subsidy, arguing that the determination of cross-subsidies is more complex than these two make it out to be.

ECC witness Colton argued that it is inappropriate to compare average costs to de-averaged revenues. In its calculation of fixed costs, Xcel did not calculate costs for different types of residential customers—e.g. those living in older apartments versus new exurban developments—but rather calculated a single, average cost. Thus, Xcel and the Department ignore the myriad of other intra-class subsidies. For example, ECC argued that low-income customers tend to live in older housing and are more likely to live in multiunit buildings. Because older buildings tend to have older utility investments (that are more fully depreciated), and because multi-unit buildings have one service drop (which is one of the primary components of fixed costs) for multiple customers, in both of these cases lower-income customers would be subsidizing higher-income customers. Similarly, ECC notes that residential customers do not pay demand charges. This means lower-use customers (especially those who do not have or do not use air conditioning) are subsidizing higher-use customers, because all demand-related costs are incorporated into per-kWh charges. ECC's aim here is not to provide an exhaustive list of cross-subsidies; rather, ECC's point is there are several potential cross-subsidies within any class, and considering some while ignoring others in inappropriate.

---

[35] A detailed discussion of the customer cost calculation is provided in the following section.

[36] These estimates were produced in the Company's Rebuttal CCOSS. Its initial estimates were $15.86 per-month for Residential customers and $16.84 for Small General Service customers.

In its Brief, CEI made a similar point:

> Subsidies between different groups within a class, as the term is used by the Department, are inevitable. For example, those who use electricity on-peak are being substantially subsidized by those who use electricity during off-peak hours. And those who build on five-acre lots requiring long service drops are being subsidized by people who live in multi-unit buildings requiring only one service drop. Because some amount of cross-subsidizing is inevitable, the key, as Mr. Chernick explained, is to avoid to the extent possible, "subsidies that encourage customers to act in uneconomic ways." Such subsidies "create real costs."[37]

Staff Comment

According to Xcel's customer cost calculation, the Small General Service customer charge is currently closer to cost (-$6.65) than the Residential (-$6.98). However, Xcel's proposed increase for Small General Service customers is *larger* than for Residential in both absolute ($1.50 compared to $1.25) and relative (15% compared to 14.3%) terms. Given the Company's goal of reducing intra-class subsidies, one would expect the increase to have been *smaller* for Small General Service, not larger.

Fixed costs calculation

In order to classify costs as customer (fixed) or demand, Xcel performed a minimum system study of its distribution system.[38] Xcel defines the fixed costs to be included in the customer charge as those that "are present if no energy is used."[39] In its calculation, the Company includes two types of costs: service costs, such as billing, meter reading, customer service and accounting; and facility costs, including the meter, service wire connection, and the minimum level of distribution facilities required to provide service. Xcel's CCOSS calculates the average, fixed, per-customer cost as $15.70 per-month for Residential customers and $16.65 for Small General Service customers.

Two parties—the Office of the Attorney General (OAG) and CEI—took issue with Xcel's customer cost calculation; their complaints are detailed below. The Department's analysis relies on Xcel's calculation of customer costs.

CEI contends that Xcel's customer cost estimate is too high because the Company misclassifies some system components as fixed costs. According to CEI, "customer charges are supposed to cover costs the utility incurs to service a *new* customer, regardless of how much electricity that *new* customer may use."[40] The difference between this definition and the Company's—"a new customer" versus "a customer"—may seem trivial, but it has significant implications for the calculation of fixed costs. Using this "new customer" standard, a utility's embedded costs—such as the poles and lines on its distribution system—would not be included in the customer cost.

---

[37] Clean Energy Intervenors, Initial Brief, September 23, 2014, at pages 14-15. Emphasis added.

[38] Xcel's minimum system study is also discussed in the CCOSS section of Staff's briefing papers, prepared by Dr. Krishnan.

[39] Exh. 105 (Huso Direct) at page 16.

[40] Clean Energy Intervenors, Initial Brief, September 23, 2014, at page 7.

Rather, only the marginal cost—such as meters, billing, customer service, and service-drop maintenance—should be included in the customer cost calculation. When CEI asked Xcel to calculate only the costs of "connecting and keeping a customer on its system," the average per-customer costs were $6.51 and $8.61 per-month for Residential and Small General Service customers, respectively. Thus, Xcel's current customer charges are too *high*, and the intra-class subsidy is running from low-use to high-use customers.

In response, Xcel argues that CEI's definition of customer costs is "extreme," and "ignores the fact that a minimum level of wires and other distribution facilities are required to make electric service available to any customer."[41] The Company cites the NARUC *Electric Utility Cost Allocation Manual* (the NARUC Manual), which lists several area-spanning costs—such as poles and fixtures or underground and overhead conductors and devices—as both demand and customer costs.

The OAG believes Xcel's estimate likely overestimates the fixed costs, due to several flaws in both its methodology and its calculation. The OAG notes that the NARUC Manual includes two methods of conducting a minimum system study: the minimum-size method and the zero-intercept method. Xcel uses the former, which is more administratively simple. However, the NARUC Manual clearly states that the zero-intercept method is more accurate in most instances.[42] The NARUC Manual also states that the minimum-size method "generally produces a larger customer component than the zero-intercept method."[43] Thus, the OAG argues that this method will overestimate customer costs. The OAG recommends that the Commission require the Company to: conduct a zero-intercept analysis in future rate cases; and, in future rate cases, provide the data necessary for other parties to replicate and verify its minimum-system analysis.

In addition to its flawed methodology, the OAG also argues that Xcel's customer charge estimate is inflated by the inputs used in its calculation. According to the OAG, in at least one instance, Xcel's minimum-system analysis does not use the smallest equipment installed on its system: Xcel uses a "1/0 Alum" cable size in its minimum-system study even though there is a smaller, less expensive cable ("#2 Alum) that is used on its distribution system. The OAG calculates that this change alone, which is just one component in one FERC account, would change the CCOSS allocation by $1.7 million. Further, Xcel acknowledges that it originally developed the per-unit installed costs of its minimum-sized equipment in 1991, and rather than updating these estimates on a regular basis, the Company simply inflates the costs using the Handy-Whitman construction cost index. In the OAG's words, "even without the substantial evidence that Xcel's study overestimates customer costs, the rough estimates produced from inflating 23-year-old data simply cannot be sufficient to conclude that one or more classes are not paying their cost of service."[44]

In response Xcel notes that it has committed to reexamine the assumptions supporting its minimum-system study before its next rate case. This includes a reexamination of its engineering assumptions, as well as an evaluation of the feasibility of performing a zero-intercept analysis. In the current case, however, Xcel "continues to support its calculation of the

[41] Exhibit 105 (Huso Direct) at page 31.
[42] NARUC Electric Utility Cost Allocation Manual, January 1992, at page 92.
[43] Ibid, at page 91.
[44] Office of the Attorney General, Initial Brief, September 23, 2014, at page 54.

customer-related portion of distribution costs as being reasonable and sufficient for ratemaking purposes."[45]

Staff Comment

The NARUC Manual states the difference between the minimum-size method and the zero-intercept method "may be relatively small."[46] The sheer magnitude of the difference between Xcel's customer charge and its calculation of customer costs suggests that even a properly executed zero-intercept model with accurate, up-to-date inputs could show that fixed customer costs are above the Company's current customer charge. In this record, however, the OAG has presented considerable evidence suggesting Xcel's estimation of fixed customer costs is inflated. Moreover, the OAG argues that the Company did not present enough data to allow its calculation to be verified.

Ultimately, it is up to the Commission to determine whether or not Xcel has demonstrated that its fixed customer costs are higher than the current customer charges. If it has not, there is no foundation for an increase in Residential and Small General customer charges.

Effect on conservation

Every party—including Xcel—that commented on the Residential and Small General Service customer charges agreed that an increase in the customer charge would reduce the incentive to conserve energy. Per-kWh charges vary directly with use, which provides customers a financial incentive to conserve energy; the customer charge, on the other hand, is fixed, meaning customers are not able to reduce it through conservation. Thus, increasing the customer charge reduces the conservation incentive by decreasing the portion of a customer's bill that varies with consumption. Further, as the OAG points out, Minn. Stat. §216B.03 directs that, "To the maximum reasonable extent, the commission shall set rates to encourage energy conservation." Several parties, including the ALJ, AARP, CEI, ECC, and the OAG, cite this conservation disincentive in their arguments against an increase to the Residential and Small General Service customer charges.

While Xcel notes that increasing the customer charge could theoretically have an impact on conservation, the magnitude of the recommended increase was selected to limit the impact on conservation. The Company notes that it is not recommending increasing the customer charge all the way to its calculation of cost. The recommended increase represents a balance between increasing intra-class equity on the one hand and limiting rate shock and decreasing the disincentive to conserve on the other. According to the Company, the amount of the increase ($1.25 or $1.50 per-month) is too small to have a "meaningful impact" on conservation.[47]

Revenue Decoupling

Two parties—CEI and the Suburban Rate Authority (SRA)—argue that the customer charge should not be increased if a revenue decoupling mechanism is approved. CEI argues that

[45] Xcel Energy, Initial Brief, September 23, 2014, at page 131.
[46] NARUC Electric Utility Cost Allocation Manual, January 1992, at page 92.
[47] Exhibit 107 (Huso Rebuttal), at page 32.

revenue decoupling and increasing the customer charge accomplish the same goal of revenue stabilization, but revenue decoupling is preferable because it avoids the disincentive for conservation by reducing the throughput incentive. In CEI's words: "The record is clear that the RDM would provide the same cost recovery as increasing fixed charges, but without the reduction in conservation incentives that accompanies higher fixed charges. For this reason, Clean Energy Intervenors oppose any proposal to increase the customer charge."[48]

Impact on low-income and elderly customers

Several parties, including AARP and ECC, argued that an increase in residential customer charges will disproportionately affect low-income and elderly customers. While Xcel does not keep data on all of its customers' income levels, the Company does keep data on participation in the federal Low Income Home Energy Assistance Program (LIHEAP), which provides energy assistance to low-income Americans.[49] AARP notes that in 2013 over 67% of Xcel's LIHEAP-recipient customers had a lower monthly usage than Xcel's residential average (mean).[50] Thus, low-income customers would be disproportionately harmed by an increase in the customer charge. And, as ECC notes, there is a statutory directive to consider ability to pay in ratemaking: Minn. Stat. §216B.16 subd. 15 states "the Commission must consider ability to pay as a factor in setting utility rates." AARP also claims that on average elderly customers use less electricity than non-elderly customers.

In response, Xcel and the Department argue that the issues of intra-class subsidy are driven by *usage*, not income, and not all low-income customers have below average consumption. Thus, the parties argue, there are some low-income, high-use customers who are subsidizing low-use, high-income customers. Moreover, Xcel argues that, even if the Commission believed a below-cost customer charge was a way to benefit low-income customers, this would be a very inefficient subsidy: in Xcel's words, "For every [LIHEAP] customer with below-average usage that would benefit from retaining the present customer charge, over 12 other customers with the same usage characteristics would benefit."[51]

In response to Xcel's and the Department's first claim, ECC notes that there are very few very-high-use, low-income customers. In 2013, on average only 1.16% of Xcel's LIHEAP customers used over 2,500 kWh/month. And for these few high-use, low-income customers, ECC notes

---

[48] Clean Energy Intervenors, Initial Brief, September 23, 2014, at page 8.

[49] There is considerable debate in the record as to whether it is appropriate to use LIHEAP recipients as a proxy for all low-income customers. Some parties, including the OAG, note that the fact that customers must opt-in to the LIHEAP program presents the potential for self-selection bias, and LIHEAP recipients may have different consumption patterns than non-LIHEAP recipient low-income customers. While Staff shares parties' concerns about self-selection bias, the evidence in this record (both from Department witness Peirce in Exhibit 422, page 7, and from the ECC in Exhibit 234, Schedule RDC-12) suggests that electricity consumption is similar between LIHEAP-recipient and non-LIHEAP recipient low-income customers. Though LIHEAP participants are not an *ideal* proxy for all low-income customers, Staff believes they present the most appropriate proxy in this particular Commission deliberation.

[50] In her testimony, AARP witness Brockway wrote "more than 60%" of LIHEAP customers had below-average usage (Exhibit 310 (Brockway Direct) at page 29). Here, Staff inserted a more precise estimate of Xcel's LIHEAP customers' bills from 2013. According to the data provided by Xcel to the OAG, Xcel's mean monthly residential usage in 2013 was 706 kWh. 474,170 of 704,220 total LIHEAP customer-months (67.3%) were under 700 kWh in 2013. Source: Exhibit 375 (Nelson Direct), at Direct Schedule REN-13, pages 5-6 (pages 241-242 of 253 in "Schedules for Testimony of Ron Nelson").

[51] Exhibit 108 (Huso Surrebuttal) at page 7.

that Xcel's POWER On program—which provides credits to high-usage LIHEAP customers that limit customers' total electric costs to less than three percent of household income—has enough funding to assist the 7,500 highest-usage LIHEAP customers. By Staff's calculation, this could cover approximately the top 12% of Xcel's LIHEAP customers, or those using over 1,150 kWh/month.

Rate shock

In their testimony on customer charges, several parties—including AARP, the Department, and the OAG—raised concerns about rate shock. The OAG notes that the percentage increase in the residential customer charge is "more than double the overall 2014 rate increase that Xcel has requested."[52] AARP argues that the size of the increase may seem small to a family with the Minnesota median-income, but "for a household of four persons with income at the federal poverty level, $23,550, [the increase] would raise that family's energy burden by almost 1%."[53]

The OAG also argues that Xcel's recent customer charge increases need to be taken into account when considering the potential for rate shock. As the table[54] below displays, if the Commission were to grant Xcel's proposed increase, the residential customer charge will have doubled over the last 8 years. And, as AARP argued, the language used in Xcel's testimony—that the proposed customer charge was a "movement toward cost"—suggests that this increase is just one step on the way to $16 (or larger) customer charges.

Date	Residential Standard	% Increase	Small General Service	% Increase
3/15/2004	$4.59		$6.88	
2/1/2007	$6.00	30.72%	$8.00	16.28%
4/1/2010	$6.50	8.33%	$8.50	6.25%
2/1/2011	$6.65	2.31%	$8.65	1.76%
10/1/2012	$7.11	6.92%	$8.61	-0.46%
1/1/2014	$8.00	12.52%	$10.00	16.14%
Proposed	**$9.25**	**15.63%**	**$11.50**	**15.00%**

Xcel notes that the percent increase of 14.3% (weighted average) for Residential and 15% for Small General Service customers is larger than its proposed overall bill increase. However, the Company argues that the increase is small in absolute terms, totaling only $15 a year for Residential customers and $18 a year for Small General Service customers. Moreover, Xcel argues that it's misleading to focus on percent increases when the current charge ($8.72 or $10) is so far below its calculation of cost ($15.70 or $16.65). In Xcel's words: "With the customer charge being so far below cost, it is not surprising that the Commission has approved increases to the customer charge in the Company's recent rate cases."[55]

---

[52] Exhibit 375 (Nelson Direct) at page 40.
[53] Exhibit 310 (Brockway Direct) at page 32.
[54] Source: Exhibit 375 (Nelson Direct) at page 41 (Table 12: Previous Customer Charge Changes).
[55] Exhibit 107 (Huso Rebuttal) at page 32.

Commission precedent

In its testimony, Xcel cites recent Commission precedent as support for a customer charge increase. In the recent Center Point Energy rate case (Docket No. 13-316), the Commission approved an increase in the customer charge from $8.00 to $9.50 per-month. The Company cites the rationale from the relevant Commission Order:

> "The Commission concludes, however, that a modest increase in the residential customer charge remains appropriate. Maintaining the customer charge at its current level would effectively increase intra-class subsidies for low-usage customers, so the principle of intra-class rate design equity supports some increase.
>
> …
>
> A $1.50 increase in the monthly residential customer charge—with a corresponding decrease in the per-therm charge—is a reasonable step toward recovery of the residential class's fixed costs in the fixed charge while appropriately minimizing conservation disincentive and possible rate shock effects."[56]

Bringing the customer charge to the full amount of Xcel's calculated fixed costs would require an increase of 82% for Residential customers. Xcel believes its proposed increase would be in keeping with the Commission's desire to improve intra-class equity while minimizing rate shock.

The OAG and the Department also cite Commission precedent in their testimonies. The OAG notes that in Xcel's last rate case, the Commission expressed concern about the potential for rate shock as the result of successive customer charge increases:

> The residential class only recently absorbed an approximately 15% increase in the customer charge in the Company's last rate case, decided little more than a year ago.
>
> While the ALJ's recommendation is more moderate than that proposed by the Company, the Commission will not adopt the increase recommended by the ALJ. The Commission finds that such an increase, coming on the heels of the prior increase, is simply too high. And, while the ALJ's recommendation might move the customer charge closer to average cost, the Commission must also avoid any increase that could result in rate shock.[57]

The Department also cited recent Commission customer charge decisions in other IOUs' rate cases. The table[58] below shows the difference between the customer charges that were requested by the utilities and the levels that were approved. As the table displays, Xcel's proposed customer charges would be considerably higher than those recently approved by the Commission.

---

[56] Docket No. G008/GR-13-316, Findings of Fact, Conclusions, and Order, at pages 51-52 (June 9, 2014).

[57] Docket No. E-002/GR-12-961, Findings of Fact, Conclusions, and Order, at page 33 (September 3, 2013).

[58] Source: Exhibit 420 (Peirce Direct), Table 7: Residential Customer Charges for Minnesota Electric Utilities, at page 13.

Company/Docket No.	Company Proposed Customer Charge	PUC Approved/DOC Proposed
Minnesota Power –E015/GR-09-1151	$9.75	$8.00
Otter Tail Power – E017/GR-10-239	$9.00	$8.50
Interstate Power & Light – E001/GR-10-276	$10.00	$8.50

In response, Xcel argues that, while the other IOUs may have lower customer charges than those Xcel proposes, many of the state's municipal and cooperative utilities have higher customer charges than those proposed by Xcel.

Administrative Law Judge (ALJ) Report

The ALJ's report discusses residential and small general service customer charges in paragraphs 778 to 816 (on pages 177 to 186). After recounting parties' positions, the ALJ provides her analysis and recommendation in paragraphs 810 to 816 (footnotes omitted):

> 810. Because the Department and the Company both have recommended increasing customer charges but by different amounts, the Administrative Law Judge will first consider whether to recommend any increase and then address the size of any increase, if necessary.
>
> 811. As discussed above, the statutory goals to be considered in rate design are that rates be reasonable and not unreasonably discriminatory; that they favor energy conservation and the use of renewable energy to the maximum extent reasonable; and that "[a]ny doubt as to reasonableness should be resolved in favor of the consumer." In addition, affordability is an important element in assessing the reasonableness of rates.
>
> 812. The Company and the Department have both recommended increases to the Residential and Small General Service customer charges based on the Company's CCOSS results and previous Commission decisions that have endorsed moving the customer charge toward cost. In this case however, CEI and the OAG both have questioned the reasonableness of relying on the Company's CCOSS results as a proxy for fixed customer costs in determining the amount of the Residential and Small General Service customer charges. While reference to the CCOSS analysis is appropriate for revenue apportionment purposes, CEI and the OAG have raised valid questions about whether the average customer costs calculated by the Company's CCOSS should be used in determining the fixed monthly customer charge. Consequently, the Administrative Law Judge finds it is appropriate to give less weight in this proceeding to the goal of moving the customer charges closer to cost as measured by the CCOSS results than in prior proceedings.
>
> 813. The record in this case also demonstrates that maintaining the Residential and Small General Service customer charges at their existing levels will help to

> encourage conservation consistent with Minn. Stat. § 216B.03. In addition, retaining the existing customer charges will promote affordability for low-use customers.
>
> 814. In the view of the Administrative Law Judge, the need to promote conservation and affordability outweigh the concerns of moving closer to the cost as measured by the Company's CCOSS results. This conclusion is buttressed by the fact that there have been a number of increases to the Company's customer charges in recent years.
>
> 815. Finally, because the Administrative Law Judge is recommending that the Commission adopt a decoupling mechanism for the Company, as discussed below in Section IX, it is not necessary to increase customer charges for revenue stability purposes.
>
> 816. For these reasons, the Administrative Law Judge concludes that retaining the current Residential and Small General Service customer charges is reasonable in this case, and recommends that the Commission reject the proposed increases of the Company and the Department.

Exceptions to the ALJ Report

The Company addressed the ALJ's analysis and recommendation on page 38 of its Exceptions:

> The Company believes its proposed customer charges were reasonable and consistent with sound rate design objectives. We acknowledge, however, that the ALJ reached a different conclusion on this topic. The Company does not challenge the ALJ's overall recommendation regarding the customer charge, but does ask that the Commission either not adopt or modify several findings because they are not supported in the record.

Specifically, the Company requests that the Commission make three changes: first, to strike the ALJ's comments on the appropriateness of applying CCOSS analysis to fixed monthly charge determinations; second, to remove the reference to affordability in paragraphs 813 and 814; and, third, to state that maintaining the customer charge "may" help encourage conservation instead of "will" help encourage conservation. A redlined version of Xcel's recommended changes can be found on pages 38 and 39 of Xcel's Exceptions.

No other party commented on the ALJ's recommendations in its Exceptions to the ALJ report.

Customer Charge Decision Alternatives

1. Adopt the ALJ's recommendation to maintain the existing customer charges for Residential and Small General Service customers. (ALJ, AARP, CEI, ECC, OAG)

2. Reject the ALJ's recommendation and increase the customer charge for both Residential and Small General Service customers by $0.50. (Department)

3. Reject the ALJ's recommendation and increase the customer charge by $1.25 for Residential customers and by $1.50 for Small General Service customers. (Xcel)

4. Modify Findings 812, 813 and 814 of the ALJ Report as proposed on pages 38 and 39 of Xcel's Exceptions to the ALJ's Report. (Xcel)

(Note: These decision alternatives correspond to alternatives VI, C (1 through 4) on p. 35 of the deliberation outline.)

Interruptible Service Discounts

PUC Staff: Andrew Twite

Statement of the Issue

What is the appropriate level of interruptible service discounts?

Introduction

Xcel offers its C&I Demand customers several interruptible service discount options. These discounts are separated into six service categories; the qualifications for each category are displayed in Staff Table 10 below. To qualify for Tier 1, customers must accept a ten-year contract with a three-year cancellation notice, while a Tier 2 contract is for five years with a six-month cancellation notice. Within tiers, service categories are separated by "performance factor," which is the percentage of a customer's maximum controllable demand that occurs during the Company's peak period (from 1 to 7 pm on weekdays in July and August).

Staff Table 10. Xcel Energy's Interruptible Service Categories and Qualifications

	Tier 1			Tier 2		
	SN	Level B	Level C	Level A	Level B	Level C
Performance Factor (% of maximum demand occurring during Peak)		65-84%	≥ 85%	< 65%	65-84%	≥ 85%
Minimum Controllable Demand	50 kW			50 kW		
Minimum Term	10 Years			5 Years		
Maximum Hours of Interruption	150 Hours			80 Hours		

Discounts are greater for Tier 1 than for Tier 2, and they are also larger for higher performance factors. The largest discount is for the Short Notice option, under which the customer consents to a shorter notice period (ten minutes instead of an hour) and allows Xcel to control the interruption.

Xcel proposes to increase the interruptible service discounts for each level, with an average increase of 5.1%. Two parties—MCC and XLI—argue that the increase in the discounts should be larger, while the Department recommends a smaller increase in the discounts. The ALJ report endorses the Department's recommendation.

Party positions

Xcel Energy

According to Xcel, its interruptible service discounts have not been increased since its 2010 rate case, but its firm demand charges were increased by 6.9% in its 2012 rate case and (as proposed) would be increased by another 11.7% in this case. Xcel proposes an increase in the interruptible service discount for all service categories. As displayed in the table[59] below, the magnitude of the increase varies by tier and performance factor, with an average increase of 5.1%.

[59] Source: Exhibit 105 (Huso Direct), Table 13, at page 27.

Present and Proposed Interruptible Discounts
NSPM-Minnesota Electric Jurisdiction
(Average Monthly Discount per kW)

Tier-PF	2-C	2-B	2-A	1-C	1-B	1-SN
Present	$4.30	$3.82	$3.10	$5.05	$4.49	$5.55
Proposed	$4.56	$4.05	$3.15	$5.35	$4.76	$5.85
Increase	$0.26	$0.23	$0.05	$0.30	$0.27	$0.30
Increase %	6.0%	6.0%	1.6%	5.9%	6.0%	5.4%

According to Xcel, the discounts are set using a market-based approach in order to attract the optimal supply of interruptible load for the short-term and to maintain it for long-term resource planning. As the Company has requested an increase in its firm demand charges, it argues that the proposed discounts will help to maintain an optimal supply of interruptible load. Xcel initially considered three options: an increase of six percent, an increase of three percent, and no increase; the Company settled on its preferred increase because it strikes "a reasonable balance between our overall interruptible rate strategy and the desire to moderate the increase in demand charges."[60]

In his direct testimony, Xcel witness Huso outlined the specific methodology used to determine the increases by service category:

> The six percent increase was applied to Performance Factor C discounts, rounded to the nearest $0.01. I then adjusted Performance Factor B rates to maintain the relative percent relationship between Performance Factors B and C. I applied a nominal percent increase to the Performance Factor A discount in recognition of its relatively lower value. Finally, I retained the $0.50 per kW differential between the Short Notice (SN) discount and the Tier 1-C discount.[61]

Department of Commerce

The Department makes two primary observations in its testimony on interruptible service discounts. First, the Department notes that Xcel only interrupted load twice for a total of 8 hours in 2013 and twice for a total of 8.75 hours in 2012. Moreover, each of these interruptions involved only Tier 1 customers; Staff notes that in 2012 and 2013 roughly 93% of Xcel's interruptible service customers were in Tier 2, meaning nearly all of Xcel's interruptible service customers had no interruptions in either year.[62] The Department's second point is that the proposed discounts are not necessary to increase interruptible load. The Department quotes Xcel witness Huso, who stated "The Company does not anticipate that the level of the proposed increase in interruptible service discounts will cause a material increase in its interruptible load."[63]

[60] Ibid, at page 27.
[61] Ibid.
[62] Additionally, it is Staff's understanding that there were no interruptions for either tier in 2014.
[63] Xcel response to Department Information Request No. 320, Exhibit 420 (Peirce Direct), attachment SLP-9.

The Department acknowledged that interruptible customers have experienced demand rate increases in recent years without a corresponding increase in discounts, and, so, some increase in the discount may be appropriate. However, in light of the factors discussed above, the Department believes a moderated increase of three percent would be more reasonable.

Xcel, XLI, and the MCC all took issue with the Department's observations. As Xcel and the MCC argued, having the *option* to interrupt provides value even if not called upon, because it reduces the Company's generation capacity requirements. To support this point, XLI cited a recent FERC ruling:

> [E]ven a limited right of interruption, if it enables the company to keep a customer from imposing demands on the system during peak periods, gives a company the ability to control its capacity costs. Therefore, that customer shares no responsibility for capacity costs under a peak responsibility method. [FN145]
> It is, thus, the right to interrupt that is critical to the analysis, and not the actual interruptions or even the number or length of such interruptions.[64]

In response to the Department's second point, Xcel argues that, while its proposed increases are not expected to significantly *increase* the amount of interruptible load, they are necessary to *maintain* an optimal supply of interruptible load. The MCC concurred, arguing that if the discounts are not increased, some customers will no longer find it cost effective to remain on interruptible service.

Minnesota Chamber of Commerce (MCC)

While it supports Xcel's efforts to increase interruptible service discounts, the MCC argues that the increases should be even larger. The MCC notes that interruptible service discounts were not increased in the last rate case, and even Xcel's largest proposed increase (6%) is considerably smaller than its proposed increase to demand charges (11%). Thus, under Xcel's proposal, the relative value of the interruptible service discounts would decrease further.

This is a problem, the MCC argues, because interruptible service customers incur costs, regardless of being called upon. These costs include: "the capital cost of equipment invested in and necessary to be available, the hiring of engineers necessary to run the equipment, scheduling and personnel costs, reporting cost, rotation of fuel costs, etc."[65] In addition, many customers that rely on emergency generation when interrupted face additional costs from new EPA regulations. According to the MCC, some of its members have left interruptible service because these costs outweigh the benefit of the discount. The MCC notes that Xcel has seen a decrease in interruptible customers and load in recent years: in 2009, Xcel had 2,243 interruptible customers with a combined load of 1,065 MW; in 2013, Xcel had 2,100 interruptible customers with a combined load of 1,037 MW.[66]

---

[64] *Mandatory Reliability Standards for the Bulk-Power System*, Docket No. RM06-16-000; Order No. 693 at 102 (March 16, 2007). Cited in Exhibit 260 (Pollock Direct), at page 51.
[65] Exhibit 345 (Maini Surrebuttal), at pages 22-23.
[66] The total interruptible load decrease from 2009 to 2013 was 2.6%, or 0.65% a year. Xcel notes that its customers have listed several reasons for leaving interruptible service, including "adjustments in environmental policy, changes in customer usage, and variation in business need." See: Xcel Energy, Reply Brief, October 14, 2014, at page 128.

The MCC also argues that the discounts do not reflect the full value of interruptible service to Xcel, even with the Company's proposed increases. The MCC notes that Xcel is able to count its interruptible load in resource planning, thus allowing it to avoid the cost of additional peaking unit additions.[67] In Xcel's last rate case, the MCC estimated that this total avoided cost—which includes the cost of a Combustion Turbine (CT), transmission, and transmission losses—was $10.18 per KW-month.

In addition, the MCC argues that recent Commission precedent supports an increase to interruptible service discounts. The MCC cites a recent Xcel Integrated Resource Plan order that requires Xcel to "evaluate higher levels of cost-effective and feasible demand response capability" and to "[c]onsider the goal of achieving participation rates for demand response programs in the top 25 percent of such programs nationwide."[68] In the MCC's words: "Demand Side Management efforts must be implemented through rates – this is exactly the time and place to put into effect objectives of the IRP."[69]

For these reasons, the MCC recommends a larger increase in interruptible service discounts than that proposed by the Department and Xcel. The MCC advocates 27.5% increase. The MCC calculated this increase by bringing Tier 1, performance factor C 25% closer to the MCC's estimate of avoided cost, which would increase the discount from $60.60 kW-year to $77.24kW-year.[70] The MCC would then have Xcel use this 27.5% increase as the baseline and replicate its proposed methodology.

Xcel takes issue with the MCC's avoided cost argument. While the Company believes the avoided cost of a peaking unit can be a useful benchmark for evaluating the value of interruptible service, it argues that it is inappropriate to set interruptible service discounts at this avoided cost. As the Company notes:

> As a peak capacity resource, interruptible load is not directly comparable to a peaking plant. Peaking plants are not bound by interruptible load limits on duration of use and advance notice requirements that reduce its relative value. Additionally, the full capacity of a peaking plant can contribute to meeting system coincident peak loads. In contrast, interruptible discounts are applied to each customer's monthly peak load, which is often less than the amount of load reduced during called interruptions.[71]

---

[67] The MCC also notes that the interruptible load is subtracted from a utility's peak demand *before* the utility applies the required planning reserve margin. Thus, the interruptible load provides the utility an avoided cost of the interruptible load times the planning reserve margin. For example, a utility with a peak demand of 100 MW, an interruptible load of 10 MW, and a planning reserve margin of 10% would have a planning obligation of 99MW [(100 MW – 10 MW) * 1.1] with the interruptible load instead of 110 MW [100 MW * 1.1] without it, for an avoided cost of 11 MW.

[68] ORDER ESTABLISHING PROCEDURAL SCHEDULES AND FILING REQUIREMENTS, *In the Matter of Xcel Energy's 2011-2025 Integrated Resource plan*, Docket No. E-002/RP-10-825 ("*2010 Xcel IRP ORDER*") (November 30, 2012) at page 12.

[69] Minnesota Chamber of Commerce, Initial Brief, September 23, 2014, at pages 26-27.

[70] Formula: Current discount + [(Avoided cost – current discount) x 0.25]; for Tier 1-C (in $/kW-year): $60.60 + [($127.16 - $60.60) x 0.25] = $77.24.

[71] Exhibit 107 (Huso Rebuttal), at page 36.

Staff Comment

As Xcel notes, there are important differences between interruptible load and a peaking facility. The figure the MCC cites as the avoided cost of interruptible power is the per-kW cost of the construction of a new 195 MW CT peaking plant plus transmission and losses. This investment would provide significantly greater benefit to a utility than it receives from its interruptible load, as a peaking unit could be deployed whenever its generation would be economical; by comparison, Tier 2 customers—which constitute roughly 93% of Xcel's interruptible customers—can only be interrupted for a maximum of 80 hours in a year, or less than 1% of all hours.[72] Thus, while interruptible load unquestionably provides value to a utility for planning purposes, it does not provide the same value as a new peaking unit.

Further, Xcel has more options to meet its resource adequacy requirements than the MCC acknowledges. The MCC rightly points out that interruptible load provides a capacity benefit, but it then argues that the avoided cost of this capacity benefit must be a new CT unit. This is a false dilemma, as the Company has several other options at its disposal to meet its planning requirements. For example, Xcel could acquire capacity resources through MISO's annual Planning Resource Auctions, bilateral capacity contracts with other Minnesota Load Serving Entities, or through diversity exchanges with winter-peaking utilities, such as Manitoba Hydro. This list is not meant to be exhaustive, but merely to illustrate that Xcel has several options to fulfill its planning reserve margin requirements. Each of these options has strengths and weaknesses, and all are considered in the Company's determination of the optimal supply of interruptible load. To select one as the avoided cost and ignore all others is inappropriate.

Xcel Large Industrials (XLI)

XLI's comments on interruptible service discounts focus on Short Notice interruptible service. To qualify for Short Notice service, a customer must have a minimum controllable demand of three MW and agree to allow Xcel to interrupt load (to a predetermined level) with only ten minutes' notice. In XLI's words, these customers "provide substantial value to NSP and other ratepayers by allowing capacity additions to be deferred and by providing contingency reserves."[73] However, under Xcel's proposal, the discounts for Short Notice interruptible service would be increased by only 5.4% while these customers' demand charges will increase by 11.7%.

Like the MCC, XLI also argues that the avoided cost of interruptible service is that of a new CT unit. XLI, which cites a higher estimate of a new CT unit than the MCC at $12.16 per-kW-month, argues that even with Xcel's proposed increase, the discount would be less than half of XLI's estimated avoided cost. Moreover, XLI witness Pollock claims that Xcel's existing CT units "require from between 16 and 68 minutes to start-up and reach full load."[74,75] As Short Notice interruptible service customers can be interrupted with only 10 minutes' notice, XLI argues this service is more akin to a quick-start CT, which is more than twice as expensive as a standard CT.

[72] Over the past three years Xcel has only called on its Tier 1 interruptible customers for a total of 8.75 hours, and it has not interrupted its Tier 2 customers once.
[73] Xcel Large Industrials, Initial Brief, September 23, 2014, at page 18.
[74] Exhibit260 (Pollock Direct), at page 54.
[75] Witness Pollock did not provide a citation for this statistic.

Accordingly, XLI argues that the interruptible service discount for Short Notice customers should be increased. Currently, Short Notice interruptible service customers have a monthly demand charge[76] of $10.27/kW and receive a discount of $5.55/kW, for a monthly net demand charge of $4.72/kW. Under Xcel's proposal, monthly demand charges would be increased to $11.48/kW. XLI recommends the monthly Short Notice interruptible discount be increased to $6.76 (an increase of 21.8%), which would keep the monthly net demand charge for Short Notice customers at $4.72/kW.[77]

Administrative Law Judge (ALJ) Report

The ALJ's Report addresses interruptible service discounts in paragraphs 817-828 (pages 186-190). After recounting parties' positions, the ALJ provided her recommendation in paragraph 828:

> 828. All parties agree that some increase in interruptible service discounts is necessary. Based on the evidence in the record, the Administrative Law Judge concludes that the Department's proposal to increase the Level C Performance Factor interruptible service discounts by three percent, and institute corresponding increases for the other performance factors to maintain the current relationship between tiers is the most reasonable. The other parties have failed to demonstrate that a larger increase is necessary to maintain an optimal supply of interruptible load.

<u>Staff Comment</u>

Three parties, MCC, Xcel, and XLI, commented on interruptible service discounts in their respective Exceptions. However, because these comments restate the positions summarized above, Staff does not repeat them here. The MCC's comments on interruptible service discounts can be found on pages 12-16 of its Exceptions, with proposed modifications to Findings 824, 825, 827 and 828 of the ALJ Report on pages 14-16. Xcel's comments can be found on pages 37-38 of its Exceptions, with proposed modifications to Finding 828 of the ALJ Report on pages 37 and 38. XLI's comments can be found on pages 23-24 of its Exceptions.

---

[76] Both firm demand charges and interruptible service discounts vary between summer and non-summer months. For simplicity, in this paragraph, Staff provides average, annualized monthly charges and discounts.

[77] However, Staff notes that if the Commission approves a smaller increase to the firm demand charge, XLI would not decrease its proposed increase so that the net monthly demand charge would remain at $4.72. Rather, XLI would still recommend that interruptible service discounts be increased to $6.76. Thus, XLI recommends that Short Notice interruptible customers' net demand charge be kept constant if the Commission approves the full amount of Xcel's proposed firm demand charge increase, but reduced if the Commission approves less than the full amount.

Interruptible Service Discount Decision Alternatives

1. Reject the ALJ's recommendation and maintain current levels of interruptible service discounts.

2. Adopt the ALJ's recommendation to increase the Level C Performance Factor interruptible service discounts by three percent, and institute corresponding increases for the other performance factors to maintain the current relationship between tiers. (ALJ, Department)

3. Reject the ALJ's recommendation and increase interruptible service discounts by: 6% for classes 1-B, 2-B, and 2-C; 5.9% for class 1-C; 5.4% for class 1-SN; and 1.6% for class 2-A. (Xcel)

4. Modify Finding 828 of the ALJ Report as proposed on pages 37 and 38 of Xcel's Exceptions to the ALJ's Report. (Xcel)

5. Reject the ALJ's recommendation and increase the interruptible service discount for Short Notice interruptible service customers by 21.8%. (XLI)

6. Reject the ALJ's recommendation and increase interruptible service discounts by: 27.6% for class 1-B; 27.5% for classes 1-C and 2-B; 27.4% for class 2-C; 25.0% for class 1-SN; and 7.4% for class 2-A. (MCC)

7. Modify Findings 824, 825, 827 and 828 of the ALJ Report as proposed on pages 14 to 16 of the MCC's Exceptions to the ALJ's Report. (MCC)

8. Reject the ALJ's recommendation and increase or decrease interruptible service discounts by some other amount.

(Note: These decision alternatives correspond to alternatives VI, D (1 through 8) on pp. 35-36 of the deliberation outline.)

Inclining Block Rates

PUC Staff: Andrew Twite

Statement of the Issue

What action, if any, should the Commission take on the proposed Inclining Block Rate design for residential customers?

Introduction

An Inclining Block Rate (IBR) is a rate design with multiple kWh usage "blocks" for any given month. The per-kWh charge is the smallest in the first block, and it increases in each subsequent block (hence the name, *inclining* block rate). In this Docket, an IBR was proposed by CEI in Exhibit 280 (Chernick Direct). As Staff Table 11 below shows, the proposal has four blocks each for the winter and summer periods.

Staff Table 11. CEI's Proposed IBR Design

	Summer		**Winter**	
Block	**Block Price**	**Block kWh**	**Block Price**	**Block kWh**
1	6.070¢	0–350	5.545¢	0–300
2	9.538¢	351–700	8.132¢	301–600
3	10.405¢	700–1,200	8.872¢	602–1,000
4	12.684¢	>1,200	9.434¢	>1,000

Initially, the proposal received support from ECC and opposition from Xcel and the OAG. At the Evidentiary Hearing, several parties—CEI, the Department[78], ECC, the Suburban Rate Authority (SRA), and Xcel—entered into a Stipulation Agreement, which requests that the Commission open a new docket to investigate CEI's IBR proposal. The ALJ's report endorsed this proposal, with some recommended modifications. The OAG opposed the Stipulation Agreement and offers an alternative decision.

In this section, Staff briefly summarizes parties' initial positions on the IBR proposal, followed by descriptions of the Stipulation Agreement and the OAG's objections to it.

Original Party Positions

CEI proposed its IBR in order to "encourage and reward conservation, by offering lower prices for smaller-use customers and higher marginal prices for the larger-use consumers who have more opportunities for conservation and energy efficiency."[79] CEI notes that IBRs are employed by several utilities, including Minnesota Power and Xcel's subsidiary in Colorado. In total, at least 55 utilities spread across 25 US states and 4 Canadian provinces have implemented IBRs. This specific proposal was designed to lower the average customer's bill while avoiding increasing any customer's bill by over 20%. Overall, CEI estimates the IBR will reduce Xcel's residential load by 2-6% over its first few years. CEI also argues this proposal would be in

[78] While the Department was not an official signatory to the Agreement, its Brief clearly states that it entered into the agreement (Department of Commerce, Initial Brief, September 23, 2014, at page 305).
[79] Exhibit 280 (Chernick Direct), at page 3.

keeping with the statutory directive to set rates to encourage energy conservation "to the maximum reasonable extent."[80]

In addition to the increased conservation incentives, ECC believes the IBR's would have a positive impact on affordability, especially for low-income customers. In ECC's words:

> [U]nder the proposed IBR, customers with average consumption will see a four percent (4.0%) annual bill decrease (rather than the 9.0% bill increase under the Company's proposal). Customers with consumption of half of the average will experience a bill decrease of more than fourteen percent (14.4%) (rather than a 9.6% bill increase under the Company's proposal).[81]

The IBR will significantly increase affordability for the majority of Xcel's low-income customers, as over two-thirds of them have below-average (mean) consumption. The bill reductions for a median-usage customer would be equivalent to an increase in LIHEAP benefits of over 30%.

Initially, the Department recommended the Commission initiate a study of CEI's proposed IBR. This study would have covered many topics, including: an estimate of the IBR's impact on conservation; an investigation of the proposal's impact on low-income customers; potential communication strategies to reduce customer confusion; and an examination of its effect on the recovery of Xcel's revenue requirement.

In its rebuttal testimony, Xcel raised several concerns with the proposed IBR. IBR, Xcel argued, is a "blunt instrument" when compared to Time-of-Use or Critical Peak Pricing programs, which "account for the fact that the cost of electricity varies by time of day, but not total monthly kWh."[82] Further, the IBR's design *reduces* conservation incentives for the majority of customers, who would be paying less under an IBR than without it. In addition, there are low-income, high-use customers who would see substantially higher bills under the IBR. The Company also expressed concern over potential customer confusion.

The OAG's criticism of the proposed IBR primarily revolves around its recent experience with CenterPoint Energy's (CPE) IBR. In the OAG's words, CPE's IBR pilot "was suspended, and eventually terminated, because it proved to have a number of detrimental and unintended consequences."[83] The OAG received several complaints from CPE customers, particularly from customers who had little or no ability to reduce their natural gas consumption, such as: people who spend their days at home, those with medical conditions that necessitate increased energy usage, and renters who have limited ability to make conservation investments. The OAG also noted the problem of buildings in which a single meter serves more than one residence.

<u>Staff Comment</u>
While Staff agrees with Xcel that IBR is a more "blunt instrument" than dynamic or critical peak pricing designs, Staff notes that these rate designs serve a different purpose from IBR. Dynamic

[80] Minn. Stat. §216B.03
[81] Energy CENTS Coalition, Initial Brief, September 23, 2014, at page 6.
[82] Exhibit 107 (Huso Rebuttal), at page 12.
[83] Exhibit 377 (Nelson Rebuttal), at page 26.

and critical peak pricing designs aim to send customers price signals that more accurately indicate the cost of producing electricity at a given time; these designs encourage customers to *shift* their load from on- to off-peak hours, not necessarily to conserve electricity. The goal of IBR, on the other hand, is to encourage customers to *reduce* their total electricity consumption during a given billing period, usually a month.

In response to the OAG's comments on CPE's recent experience with IBR, Staff believes there are key differences between gas and electric service that will impact customer response to an IBR. In northern climates with extreme winter weather, customer demand for natural gas varies much more dramatically by season than does demand for electricity. Thus, the customer impact of an IBR will be much more dramatic for gas service than for electric if the IBR monthly energy usage blocks or tiers are the same for peak and off-peak months. Staff believes Minnesota Power's (MP) IBR experience may provide a more appropriate comparison: when MP's residential rate structure changed from three-blocks (with the first block a lifeline energy allowance and the second a lifeline discount) and instituted a five-block IBR for its residential electric customers in 2009, it did not see evidence of substantial customer confusion, and it has received a relatively small number of complaints about the program.[84]

Stipulation Agreement

At the Evidentiary Hearing, CEI, the Department, ECC, the SRA, and Xcel entered into a Stipulation Agreement (the Agreement), which requests that:

> [T]he Commission open a new docket and require Xcel to file a proposal for an IBR rate structure, in the form of a Compliance Filing, 120 days after the Commission issues its Findings of Fact, Conclusions of Law and Order in this proceeding. All of the evidence and argument regarding IBR from this rate case—including proposals and concerns, from parties and the public—would be incorporated into the new proceeding. This separate docket will allow for further development of this rate structure and provide parties additional time to discuss issues related to IBR.[85]

Under the Agreement, Xcel's compliance filing would be required to include CEI's IBR proposal, and Xcel would also have the option of including one alternative IBR design for consideration. The filing would also include the Company's IBR customer education proposal.

In addition to the compliance filing, the Agreement also requires the Department to convene stakeholder meetings to discuss concerns raised in the testimony and to provide a report to the Commission within 90 days of Xcel's compliance filing. The meetings would discuss, without limitation:

> [T]he identification of any additional customer groups that should be excluded from an IBR proposal, considerations for customer education, a methodology for mitigating extended billing periods, an explanation of billing system changes

[84] See Minnesota Power's Annual Evaluation of Residential Five-Block Rate Design, filed on January 11, 2013 and April 28, 2014 in Docket 09-1151.
[85] Exhibit 135 (IBR Stipulation Agreement), at pages 1-2.

> necessary to implement IBR and the cost of those changes, and the impact such a proposal may have on other Xcel tariffs, including but not limited to, net metering, Community Solar Gardens, and the Residential Savers Switch.[86]

Of the parties that commented on the IBR in the record, all agreed to the Stipulation Agreement with the exception of the OAG.

Office of the Attorney General's Objections to the Stipulation Agreement

In its Brief, the OAG took issue with the restrictions included in the Agreement. In the OAG's words, "the process outlined in the Stipulation limits the number of IBR proposals that may be considered, the entities who may make specific IBR proposals, and, most importantly, the time-frame in which interested parties may discuss and attempt to address any negative impacts of the IBR on specific customers."[87,88] The OAG notes that, when the Colorado PUC considered an IBR for Xcel, it selected the simplest of the nine options it was presented.

Due to these limitations, the OAG recommends that the Commission reject the Stipulation Agreement. If the Commission is interested in further pursuing and IBR for Xcel, the OAG recommends it open a general docket without the restrictions outlined in the Stipulation Agreement. This general docket should consider all options, so that the Commission could compare the pros and cons of each and choose the best available option.

Administrative Law Judge (ALJ) Report

In paragraph 841, the ALJ's report endorses the stipulation agreement, but recommends two modifications:

> 841. The Administrative Law Judge concludes that the record demonstrates IBR is an effective tool for promoting conservation, and agrees with the parties to the stipulation that the proposed IBR warrants further review. The stipulation appears to set forth an appropriate process for review and resolution of the IBR issue, with two suggested modifications. First, to address the OAG's concern, the Administrative Law Judge suggests that the Commission allow all parties the opportunity to submit alternative proposed IBR pricing structures for consideration in the new docket. It would be unfair to the other parties to limit consideration only to the CEI proposal and a Company proposal. Such a limitation could result in exclusion of a more reasonable IBR rate structure. Second, the Commission should require the parties to the IBR stakeholder meetings to specifically address the issue of potential impacts on high-use, low-income customers, and require the parties to identify possible means of addressing the impacts. In the current docket, the Department, the OAG, and the Company all raised concerns about the potential impact of an IBR pricing structure on high-

[86] Ibid, at page 2.
[87] Office of the Attorney General, Initial Brief, September 23, 2014, at page 72.
[88] Staff notes that, while the Agreement does restrict the amount of time in which the Department may conduct its stakeholder process, the Commission would have the option to open an additional comment period for the docket, which could provide additional time for record development.

> use, low-income customers. The Administrative Law Judge agrees that these concerns should be addressed in more depth if the Commission opens a new docket to address IBR.

Exceptions to the ALJ Report

In its Exceptions, the OAG noted that it supports the modifications recommended by the ALJ, but it still believes they do not go far enough. If the Commission is interested in further examining IBR, the OAG recommends the Commission "open a broad generic docket to investigate all possible alternative rate designs" and to "ensure that the generic docket permits enough time to thoroughly examine all possible alternative rate designs."[89] The OAG proposes modifications to Finding 841 of the ALJ's report, which can be found on pages 33 and 34 of the OAG's Exceptions.

Inclining Block Rate Decision Alternatives

1. Adopt the ALJ's recommendation to approve the process outlined in the IBR Stipulation Agreement (Exhibit 135) with the modifications suggested in paragraph 841 of the ALJ's report. (ALJ)

2. Reject the ALJ's recommendation and approve the process outlined in the IBR Stipulation Agreement (Exhibit 135). (CEI, the Department, ECC, SRA, Xcel)

3. Reject the ALJ's recommendation and replace the process outlined in the IBR stipulation Agreement with a general docket on rate design alternatives for Xcel's residential electric customers as described in the OAG's Exceptions. (OAG's secondary position).

4. Reject the ALJ's recommendation and take no action on IBR. (OAG)

5. Modify Finding 841 of the ALJ Report as proposed on pages 33 and 34 of the OAG's Exceptions to the ALJ's Report. (OAG)

(Note: These decision alternatives correspond to alternatives VI, E (1 through 5) on p. 36 of the deliberation outline.)

[89] Office of the Attorney General, Exceptions, January 20, 2015, at pages 33-34.

Coincident Peak Billing

PUC Staff: Susan Mackenzie

Statement of the Issue

Should the Commission adopt the MCC proposal to require Xcel to offer coincident peak billing for C&I demand-billed customers that have two or more separate services (each 500 kW or greater) on a single contiguous site?

Introduction

Under existing service, a single business on contiguous properties that has multiple metered locations is billed separately for each metered location. This is commonly referred to as non-coincident peak billing. If the maximum demand for each metered location occurs at different times during the month, the total of all billed demands for the month may exceed the amount that would have been billed if the entire business site was metered and billed through a single metered location.

In Xcel's last rate case, MCC also proposed Xcel's tariffs be modified to allow for coincident peak billing. The Commission did not accept the proposal, concluding that it was not sufficiently developed, especially the cost implications.[90]

In this case, MCC again proposed that Xcel modify its C&I tariff to facilitate coincident peak billing for demand-billed customers that have two or more separate services (each 500 kW or greater) on a single contiguous site. Under coincident peak billing as proposed by MCC, the 15-minute billing demands of all the meters would be synchronized and added together at each interval of time. The customer would then be billed for the aggregated total rather than the separate peak demands.

Under MCC's proposal, in order to take advantage of coincident peak billing, the qualified customer would need to install and be responsible for the costs associated with interval recording meters and a totalizer for the qualified business site.

Xcel opposed MCC's proposal. The ALJ found MCC's proposal was not sufficiently developed to be adopted and recommended it be denied.

Party Positions

Minnesota Chamber of Commerce (MCC)

MCC argued that demand at individual meters on one customer's property often peaks at different times, providing system diversity. This merits allocating less responsibility for both generation and transmission resources to that customer and reducing that customer's billing demand. Coincident peak billing allows the customer to capture any system diversity benefits through reduced billing demand.

[90] Findings of Fact Order, in Docket No. 12-961, issued September 3, 2013, page 13.

To address the Commission's concerns from the last rate, MCC issued two Information Requests (MCC IR 232 and 244) concerning customer costs, potential revenue loss, and the impact on other customers. MCC argued that the IR responses confirm that Xcel will need to spread revenue loss that results from fewer demand billing units (for generation and transmission components only) to those customers not taking the service. However, MCC maintained that the revenue loss will be minimal because the proposal only affects nine customers. Regardless, MCC argued that these costs should not be recovered from customers who do not cause them.

MCC argued that the rewiring of facilities as proposed by Xcel is not a practical solution nor is it efficient for customers to redesign a system when interval recording meters can be used. MCC argued that setting a threshold at 500 kW at two or more meters limits the diversity savings allocated to other customers while allowing coincident billing customers to capture the diversity benefit they create. Also, MCC is not opposed to a reasonable meter charge to recover the costs of billing system changes.

Xcel Energy (Xcel)

Xcel opposed the proposed change and argued that customers are responsible for electric wiring past the point of metering and may change wiring configurations at their site to accommodate a single service entrance. If a customer considers the diversity between multiple service points to be significant, the potential bill savings from lower billed demand quantities can be weighed against the cost of changing their wiring configuration.

Xcel also argued that MCC made the proposal without regard to the potential amount of diversity within a customer site; the amount of diversity at one customer site could be very small if all services are related to the main processes that use electricity. In the past, the Company offered an experimental demand aggregation rider, which was canceled at the end of 2001. Study of the rider identified smaller than expected diversity on customer sites. Diversity ranged from 2.4 to 9.8 percent, indicating that there may not be significant savings associated with coincident peak billing.[91]

According to Xcel, MCC's proposal would require expensive billing process changes that would benefit only a few customers, and MCC has not addressed cost recovery for these billing process changes. Moreover, the Company argued that such a significant change is unnecessary when customers already have the ability to address the issue on their own by weighing the additional costs of changing their wiring against the savings associated with a unified peak demand.

Lastly, the Company suggested that the MCC proposal is not consistent with established rate design because although it is appropriate to recognize diversity for billing generation capacity costs, it is not appropriate to recognize diversity for distribution capacity costs.

Administrative Law Judge (ALJ) Report

The ALJ's Report addressed the issue of coincident peak billing in paragraphs 945-953 (pages 212-214). After summarizing the parties' positions, the ALJ provided her recommendation in paragraph 953:

[91] Xcel Energy Compliance Report (01-678) filed May 1, 2001.

> 953. While MCC's current coincident peak billing proposal has more specificity than its last proposal, the Administrative Law Judge concludes that its current proposal is still not sufficiently developed to show that it will result in reasonable rates. MCC has not addressed how the cost of implementing the new billing system would be recovered, other than to express its acceptance of a reasonable meter charge. MCC has not provided any evidence to demonstrate that it would be cost-effective for any of the nine customers to implement coincident peak billing if the customer is responsible for the cost of the new meters and also a reasonable meter charge. Finally, MCC has not explained how its current proposal differs from the experimental demand aggregation rider program cancelled by the Company in 2001 due to lack of interest.

Exceptions to the ALJ Report

MCC argued that the ALJ's Findings were inconsistent with respect to coincident peak billing and the definition of contiguous. Specifically, MCC provided recommended modifications to Findings 953 and 958, which can be found on pages 16 and 17 of its Exceptions to the ALJ's Report.

Coincident Peak Billing Decision Alternatives

1. Adopt the ALJ recommendation to deny MCC's proposal for coincident peak billing. (ALJ, Xcel)

2. Reject the ALJ's recommendation and adopt the MCC's proposal to require Xcel to offer coincident peak billing for C&I demand-billed customers that have two or more separate services (each 500 kW or greater) on a single contiguous site. (MCC)

3. Modify Findings 953 and 958 of the ALJ Report as proposed on pages 16 and 17 of the MCC's Exceptions to the ALJ's Report. (MCC)

(Note: These decision alternatives correspond to alternatives VI, F (1 through 3) on p. 36 of the deliberation outline.)

Definition of Contiguous

PUC Staff: Susan Mackenzie

Statement of the Issue

Should the Commission require Xcel to include the statutory definition from Minn. Stat. § 216B.164, Subd. 2a (e) in the Company's Electric Rate Book to define the term "contiguous property"?

Introduction

Xcel's current tariffs do not include a definition of the term "contiguous property." The term is used in Xcel's Minnesota Electric Rate Book in the General Rules and Regulations governing Use of Service, as follows:

> The customer may combine the supply of electricity through one meter and one service to two or more buildings or occupancy units if they are located on the same or contiguous parcels of property and occupied by the same customer, solely for the customer's own use.[92]

MCC proposed that Xcel be required to use the definition of "contiguous property" from Minn. Stat. § 216B.164, Subd. 2a (e) to define the term for the purposes of: (1) use in the Company's Electric Rate Book, Section No. 6, Sheet No. 19.3 (General Rules and Regulations governing Use of Service), (2) future applications for solar power PPAs, and (3) the coincident peak billing option proposed by MCC in this rate case.

Under Minn. Stat. 216B.164, Subd. 2a (e), the term "contiguous property" is defined as:

> (e) "Contiguous property" means property owned or leased by the customer sharing a common border, without regard to interruptions in the contiguity caused by easements, public thoroughfares, transportation rights-of-way, or utility rights-of-way.

Xcel does not support MCC's proposal. The ALJ recommended the Commission adopt the proposal.

Party Positions

Minnesota Chamber of Commerce (MCC)

MCC claimed that the Company's current definition of "contiguous property" lacks clarity in the tariff book and is subject to inconsistent application. By adopting the statutory definition, customers will be able to more accurately plan metered serviced sites for their business locations.[93]

---

[92] Minnesota Electric Rule Book, Section No. 6, Sheet No. 19.3.
[93] MCC Reply Brief at page 11; ALJ Finding 957.

MCC argued that for purpose of applying coincident peak billing, Xcel should use the definition of "contiguous property" found in Minn. Stat. § 216B.164, Subd. 2a (e).[94] MCC maintained that in setting out this definition the legislature agreed that Xcel did not have a clear definition of "contiguous property" in its tariffs. MCC also proposed the adoption of the new definition to use in negotiating PPAs with developers utilizing contiguous property, and where lack of a clear definition might limit coincident peak billing.

MCC argued that the current Minnesota Electric Rate Book rules are not sufficient. Xcel currently references "contiguous" in a couple places, including: (1) Section No. 6, Sheet No. 19.3, Use of Service, and (2) Section No. 6, Part 3.13, which deals with Demand Aggregation wherein contiguous is not used but discussed without defining it.

MCC testified that in the past Xcel has interpreted "contiguous" in a limited manner, inconsistent with the new statutory definition, disallowing applications in the case of interruptions in property lines caused by roadways and other rights of way. MCC proposed that Xcel adopt the above definition of "contiguous property" for the purpose of approving solar projects at a customers' plant site involving a third party, non-utility ownership of solar facilities on contiguous customer property along with energy delivery under a PPA, without size limitation. In its Brief, MCC stated:

> If customers cannot combine their load at any one contiguous campus, or otherwise participate in Distributed Generation across roadways and other easements on property which they control, Distributed Generation efforts will be stifled as economies of scale will not be able to be achieved. Additional support for the Chamber's proposal is found in Xcel's last Integrated Resource Plan which states Xcel should evaluate "higher levels of distributed generation, including industrial-sized distributed generation… and combined heat and power." Customers cannot practically consider industrial-sized distributed generation of combined heat and power if their campuses are broken up and they cannot propose projects that have economies of scale. The above definition should be incorporated in Xcel's Rules.

MCC noted in Rebuttal Testimony that Xcel did not propose its own definition of contiguous property but dismissed the statutory definition proposed by MCC. MCC also pointed out that although Xcel provided a definition of contiguous property in response to MCC Information Response 251, the Company did not propose to incorporate the definition into Company tariffs, nor did the proposed definition provide clarity.

If Xcel does not use the new statutory definition, MCC argued it would limit tax exempt institutional customers' ability to benefit from tax and other incentives. In order to have clear rules that will provide ratepayers with the appropriate signal to plan and manage power costs, MCC believes there must be an appropriate definition consistent within Minnesota law. In the absence of any other definition, MCC believes the Commission should accept the proposed language, which mirrors state law.

---

[94] During the 2013 legislative session, the legislature amended Minn. Stat. § 216B.164, which governs cogeneration and small power production. The most significant change was to increase the net-metering threshold capacity.

Xcel Energy (Xcel)

Xcel opposed the MCC proposal for a formal adoption of the definition of the term "contiguous property". It argued that the new statutory definition of contiguous property is not applicable for purposes other than meter aggregation used with net metering as described in Minn. Stat. § 216B.164. In response to MCC Information Request 236, Xcel stated:

> The Company, in this proceeding, is not seeking to recover costs for solar projects arising from the solar legislation recently enacted in the State of Minnesota. For that reason, we struggle with understanding the relevance of this question in this proceeding. With that said the cited provision can be found at Minn. Stat. § 216B.164, Subd. 2a. In context, it is a definition to be used as part of Minn. Stat. § 216B.164. The only time this "contiguous property" defined term is used in this statute is in Subd. 4a on the issue of aggregation of meters used with net-metering, which states:
>
> > Subd. 4a. Aggregation of meters. (a) For the purpose of measuring electricity under subdivisions 3 and 3a, a public utility must aggregate for billing purposes a customer's designated meter with one or more aggregated meters if a customer requests that it do so. To qualify for aggregation under this subdivision, a meter must be owned by the customer requesting the aggregation, must be located on **contiguous property** owned by the customer requesting the aggregation, and the total of all aggregated meters must be subject to the size limitation in this section. (Emphasis added)
>
> This definition is not applicable for purposes other than meter aggregation used with net metering as described in Minn. Stat. § 216B.164. The Company's proposed approach to meter aggregation, including adopting the term contiguous property, was set forth in its petition in Docket No. 13-642.

In response to MCC Information Request 251, the Company explained that the use of the term "contiguous property" in the current Minnesota Electric Rate Book is used to refer to a single physical customer site or location, as distinct from customer accounts at different geographical locations. Moreover, Xcel testified that there is no need to have a specific definition for the term as used in the current tariff; if a customer can wire a site in a way that presents one metered service location, then the customer can take advantage of demand aggregation and the structure of the parcel of property holding the metered service location is irrelevant.[95]

Xcel also argued that since MCC's coincident peak billing proposal is unreasonable, no definition of the term is needed in that specific context. Minnesota law addresses the definition of contiguous in the context of solar projects and the Company has already provided its interpretation of the term as it appears in tariffs in response to MCC Information Request 251.[96]

---

[95] ALJ Finding 956 and Tr. Vol. 2 at 186-89 (Huso).
[96] Exhibit 136.

Xcel explained that the Commission established a rulemaking advisory group in Docket No. E999/R-13-729 to help implement significant portions the new solar law, including a proposed new rule implementing the provisions for aggregation of meters under Minn. Stat. § 216B.164, subd. 4a.

Administrative Law Judge (ALJ) Report

The ALJ's Report addressed the issue of the definition of contiguous in paragraphs 954-958 (pages 214-215). After summarizing the parties' positions, the ALJ provided her recommendation in paragraph 958:

> 958. The Administrative Law Judge concludes that MCC's request for adoption of the statutory definition of "contiguous" as part of the Company's current tariff is reasonable. Although the Administrative Law Judge has concluded that coincident peak billing is not appropriate under the facts in this record, MCC has shown that use of the statutory definition of "contiguous" would be beneficial. Formal application of the statutory definition in a revised tariff would provide uniformity and benefit to current customers looking to take advantage of demand aggregation.

Exceptions to the ALJ Report

Xcel did not file an exception to the ALJ Findings on this issue.

Definition of Contiguous Property Decision Alternatives

1. Adopt the ALJ recommendation to require Xcel to include the statutory definition of the term "contiguous property," found in Minn. Stat. 216B.164, Subd. 2a (e), in the Company's Electric Rate Book, Section No. 6, Sheet No. 19.3. (ALJ)

2. Adopt MCC's recommendation to require Xcel to include the statutory definition of the term "contiguous property" found in Minn. Stat. 216B.164, Subd. 2a (e): (1) for use in the Company's Electric Rate Book, Section No. 6, Sheet No. 19.3 (General Rules and Regulations governing Use of Service), (2) in future applications for solar power PPAs, and (3) in the coincident peak billing option proposed by MCC in this rate case. (MCC)

3. Reject the ALJ's recommendation and adopt the Company's position that no formal definition for "contiguous property" be adopted as part of the rate case. (Xcel)

4. Reject the ALJ's recommendation and require Xcel to file a definition of the term "contiguous property" for application in the Company's Electric Rate Book, Section No. 6, Sheet No. 19.3. (Staff)

(Note: These decision alternatives correspond to alternatives VI, G (1 through 4) on p. 37 of the deliberation outline.)

Renewable Energy Purchase Rider

PUC Staff: Susan Mackenzie

Statement of the Issue

Should the Commission require Xcel to develop and present a proposal for a renewable energy purchase tariff available to large, high load factor customers, as part of its next rate case?

Introduction

XLI proposed that Xcel work with interested parties to establish a new renewable energy purchase option ("Renew-A-Source") for industrial customers. Xcel indicated it was willing to work with XLI and other interested stakeholders to develop a program but that this could take time. Therefore, Xcel recommended the Commission not set a particular deadline for proposing a tariff.

The ALJ found XLI's proposal to be worthy of further review and recommended that Xcel be required to present a proposal for a renewable energy purchase option as part of its next rate case.

Party Positions

Xcel Large Industrials (XLI)

XLI proposed a new program for large, high load factor customers that would allow the sale of renewable energy from new resources directly to these customers at rates below what they currently pay. One of the purposes of the program would be to address what XLI believes are uncompetitive industrial rates offered by Xcel.

The Company currently offers a Voluntary Renewable and High Efficiency Energy Purchase Rider (i.e. the WindSource Program) under which a customer can elect to contribute to the development of renewable energy by paying a monthly premium for each 100 kWh block of renewable energy entered into the program. The energy in the program is exempt from the fuel clause. However, the XLI testified that the WindSource Program is not a viable option because it results in a net increase in the cost of electricity for customers. Therefore, the WindSource Program provides little incentive for large C&I customers to purchase renewable energy.

XLI testified that there are "synergies" between high load factor customers and the attributes of renewable resources. To the extent that these synergies can be tapped, this might help to lower the cost of renewable energy overall as well as the rates paid by large C&I customers.

XLI noted that one of the primary limitations of renewable energy, specifically wind, is its off-peak nature and intermittency. However, high load factor customers that operate primarily off peak have load profiles that more closely match the availability of the wind resource. Therefore, if renewable resources were purchased to directly meet the around-the-clock/off peak demand of large, high load factor customers and the purchase was offered directly to these customers under a separate tariff, such a program could assist in meeting state renewable energy standards.

XLI proposed that Xcel develop a specific tariff under which the Company would purchase renewable energy directly for large, high load factor customers under long-term agreement ("Renew-a-source"). The aim of the program would be to "match" the output of a defined portfolio of renewable resources with the qualifying large customers' load shapes. XLI noted that the cost of the energy produced from the renewable resource would need to be made affordable to the large customers. XLI believes that, as a result of the program creating more demand for renewable resources by creating a stable source of long term funding, Xcel would have leverage to negotiate better pricing, reducing rates paid by participating customers.

In Direct Testimony, XLI witness Mr. Pollock outlined provisions for how the program might be structured and proposed that they provide the basis for further discussions. They included: applicability, availability, contract quantity, energy rate, and additional billing adjustments.[97]

XLI recommended that Xcel be required to work with interested parties to develop the new program/tariff following XLI's proposed guidelines. It suggested that Xcel's proposed tariff be filed as part of the next rate case, or separately within 60 days after the Final Order in this rate case, whichever is earlier.

In Rebuttal Testimony, XLI noted that Xcel offered to discuss the proposal at the same time it begins discussions on fuel clause reform. However, XLI witness Pollock argued there is no relationship between the two issues and fuel clause reform should be addressed on a utility-specific basis, while uncompetitive industrial rates need immediate attention.

Xcel Energy (Xcel)

Xcel expressed a commitment to pursue discussions with stakeholders on XLI's proposed program/tariff. However, the Company also recommended against establishing a firm timeline for filing a specific tariff, as it believed it may "take some time to develop a proposal that is appropriate for all stakeholders.[98] The Company committed to initiate discussions on a program when it begins discussions on the FCA issue.

The Company explained that multiple statutory provisions are relevant to the Company's rate design. The Commission must balance competing directives and appropriately incorporate all relevant positions. Arguments that seize on certain legislative directives while ignoring others are contrary to Minnesota law. The Company believes its rate design proposals strike an appropriate balance against all relevant statutory considerations and should be approved.[99]

Administrative Law Judge (ALJ) Report

The ALJ's Report addressed the issue of a renewable energy purchase option in paragraphs 959-963 (pages 215-216). After summarizing the parties' positions, the ALJ provided her recommendation in paragraph 963:

[97] Exhibit 260 (Pollock Direct) at pages 61-62.
[98] Exhibit 100 (Clark Rebuttal) at pages 47-48.
[99] Xcel Reply Brief at pages 125-126.

> 963. The Administrative Law Judge concludes that XLI's concept of creating a new tariff program to provide renewable energy to large high-load factor customers is worthy of further review. If well structured, such a program could make renewable energy affordable to large C&I customers and further the state energy policy of encouraging use of renewable energy resources. Therefore, the Administrative Law Judge recommends that the Company be required to present a proposal for a "Renew-A-Source" tariff as part of its next rate case.

<u>Staff Comment</u>

Although Xcel expressed a commitment to work with stakeholders on XLI's proposed tariff for a large customer renewable energy purchase option, the Company did not provide feedback or testimony on the specifics of the tariff proposed by XLI mentioned above. It is unclear to Staff whether the ALJ is recommending Xcel merely be required to submit a large industrial customer renewable energy purchase option, or if Xcel will be required to submit a specific "Renew-A-Source" tariff that complies with XLI's specific recommendations. Staff believes a better product may result if Xcel and stakeholders are not bound by the specific recommendations offered by XLI. Accordingly, Staff proposes Decision Alternative 3, which requires Xcel to work with stakeholders to develop a renewable energy purchase option without binding it to the specific recommendations XLI put forth in its discussion of a "Renew-a-Source" tariff.

Exceptions to the ALJ Report

Xcel did not comment on this issue in its Exceptions to the ALJ's Findings.

Renewable Energy Purchase Option Decision Alternatives

1. Adopt the ALJ recommendation to require Xcel to present a proposal for a "Renew-a-Source" tariff for large industrial customers as part of its next rate case. (ALJ, XLI)

2. Reject the ALJ's recommendation and require Xcel to work with XLI and other interested stakeholders to develop a renewable energy purchase option program that addresses the goals outlined by XLI in the record of this case, but do not set a specific deadline for filing a tariff proposal. (Xcel)

3. Reject the ALJ's recommendation and require Xcel to work with the XLI and other interested stakeholders to develop a renewable energy purchase option program that addresses the goals outlined by XLI in the record of this case. The final tariff may, but need not, comply with the specific recommendations provided by XLI in Exhibit 260 (Pollock Direct) at pages 61-62. (Staff)

(Note: These decision alternatives correspond to alternatives VI, H (1 through 3) on p. 37 of the deliberation outline.)

Definition of On-Peak Period

PUC Staff: Susan Mackenzie

Statement of the Issue

Should the Commission require Xcel to modify the definition of "on-peak period" as currently applied in the Company's time-of-use tariffs?

Introduction

Xcel currently defines the "on- peak period" as the hours between 9:00 a.m. and 9:00 p.m., Monday through Friday, with the exception of seven specified holidays. This term is used in Xcel's time-of-use tariffs and is subject to change with the Company's system operating characteristics.

XLI proposed to modify the on-peak period in Xcel's time-of-use tariffs. Xcel opposed the modification and the ALJ recommended against the change.

Party Positions

Xcel Large Industrials (XLI)

XLI proposed to modify the on-peak period in Xcel's time-of-use tariffs by limiting it to summer months to recognize that Xcel is a summer-peaking utility with predominant summer capacity.[100] XLI provided the following reasons for the change. First, MISO has changed its resource adequacy requirements and now requires load serving entities, like Xcel, to meet MISO's projected annual coincident peak load. Under the MISO construct, the Company will incur additional costs if it is unable to meet the MISO summer peak. Second, Xcel revised its demand allocation methodology to allocate the capacity-related portion of generating plant using the summer coincident peak. Previously, Xcel used the average of the summer and non-winter coincident peaks; for this reason, XLI concluded that electricity demand in the non-summer months is not relevant in determining the amount of capacity needed to provide reliable service. Also, XLI argued that rate design should track the cost allocation.

XLI argued that time-of-use rates are intended to send price signals that electricity usage during on-peak periods is more expensive; higher on-peak prices are intended to encourage customers to minimize on peak usage and/or shift usage to off-peak hours. XLI witness Pollock provided an analysis of Xcel's and MISO's hourly loads, which shows that peak usage hours tend to occur more during summer months.[101] However, because Xcel's current definition of the on-peak period occurs outside of summer months, it does not encourage customers to shift usage away from summer peak months. Practically, XLI noted that it may be difficult for customers to avoid demand charges when billing demand is based on a 12-hour peak period on all weekdays throughout the year.

[100] Exhibit 260 (Pollock Direct) at 56-58.
[101] Exhibit 260 (Pollock Attachments to Direct) Schedules 13 and 14.

XLI argued that the same definition of the on-peak period does not have to apply uniformly to energy and demand charges but that the designation of on-peak hours should recognize the importance of the high-demand hours in applying demand charges. The only limitation being Xcel's billing system.

Xcel Energy (Xcel)

Xcel argued there is no basis for XLI's proposal. For C&I demand-metered customers, the on-peak period is principally used to differentiate energy and fuel cost charges by on-peak and off-peak periods, not for differences in seasonal use. The XLI proposal is based on the system seasonal peak capacity differential, which is accurately recognized in the seasonal demand charge differential and does not relate to energy and fuel cost charges; the Company agreed that its current seasonal demand charges reflect the cost difference associated with system seasonal peak capacity differentials and therefore no change is necessary.

Administrative Law Judge (ALJ) Report

The ALJ's Report addressed the issue of the definition of on-peak period in paragraphs 964-967 (pages 216-217). After summarizing the parties' positions, the ALJ provided her recommendation in paragraph 967:

> 967. The Administrative Law Judge concludes that XLI has not shown that a change in the definition of "on peak period" would result in more reasonable rates. XLI's proposal fails to recognize that the current definition of "on peak" properly accounts for the hourly differences that occur in all months throughout the year. In addition, the Company's existing seasonal demand charges reflect the cost difference associated with seasonal peak capacity differentials, making the proposed change unnecessary.

Exceptions to the ALJ Report

The XLI took exception to the ALJ's Findings and Recommendation and noted that Xcel has the burden of showing that its rates are just and reasonable. XLI maintained that Xcel offered limited support for the status quo for the on-peak period and did not provide justification for why XLI's proposal would not allow customers to respond more effectively to price signals. XLI requested that the Commission reject the ALJ's recommendation and instead adopt XLI's proposal to modify the definition of the on-peak period.

Definition of On-Peak Period Decision Alternatives

1. Adopt the ALJ recommendation to deny the XLI proposal to modify the definition of "on-peak period" as currently applied in the Company's time-of-use tariffs. (ALJ, Xcel)

2. Reject the ALJ's Finding in paragraph 967 and adopt the XLI proposal to modify the definition of "on-peak period" applied in the Company's time-of-use tariffs by limiting on-peak periods in time-of-use tariffs to summer months (June, July and August). (XLI)

(Note: These decision alternatives correspond to alternatives VI, I (1 through 3) on p. 38 of the deliberation outline.)

Conservation Cost Recovery Charge and the CIP Adjustment Factor

PUC Staff: Susan Mackenzie

Introduction

In Direct testimony, the Company proposed to zero out and remove the Conservation Cost Recovery Charge (CCRC) from base rates and recover all CIP program costs through the CIP Adjustment Factor, also known as the Conservation Cost Recovery Adjustment (CCRA).[102] The Department supported the Company's proposal, finding it would be more administratively efficient.[103] The Department recommended the CCRC be zeroed out when final rates are implemented, and the Company agreed to this timeline. The Company also agreed to submit an updated CCRA filing 90 days before final rates are estimated to go into effect.[104] In the event the Commission did not adopt Xcel's proposal, the DOC provided the appropriate level of test year CIP expenses.[105]

The ALJ's Report considered this a resolved issue, so it does not provide analysis of this issue.

<u>Staff Comment</u>
In response to Staff's request, Xcel provided Exhibit 150, which shows the increase in the monthly CIP Adjustment Factor (CCRA) that would result Xcel's proposal to zero out the CCRC. This would move an additional 0.3051 cents/kWh to the CCRA following the rate case, an increase of over 240%.[106] The CCRA is part of the resource adjustment charge (RAC), which is a separate line item on the bill.[107] While there would be an equal dollar amount reduction to base rates from removing the CCRC, there would be no corresponding percentage reduction in base rates that customers would notice; in fact, base rates overall will increase as a result of the rate case. If the Commission does approve the Xcel proposal, Staff suggests a requirement that the customer notice of new rates include an explanation of this change.

Setting out all charges related to CIP as a separate component of the bill does not comport with usual purpose and practice regarding riders. In general rate riders are designed to either:

1. True up differences between actual costs and what is built into base rates. The fuel clause and the CCRA are examples.

2. Allow the utility to begin collecting revenues related to specific projects without waiting for a rate case. These projects are subsequently included in base rates in a future rate case. Most riders fall into this category: renewable rider (for a utility-owned project), transmission rider, mercury emissions rider, environmental riders (OTP Big Stone 1 upgrades, MERP) are examples.

---

[102] Exhibit 102 (Peppin Direct) at pages 32-33.
[103] Exhibit 417 (Davis Direct) at pages 3-7.
[104] Evidentiary Hearing Transcript, Vol. 2 at 157-159 (Peppin)
[105] Exhibit 417 (Davis Direct) at page 7.
[106] The test year CIP expense is over $90 million.
[107] Since the CCRA is only one component of the RAC, the percentage increase in the RAC that customers would see would be less than 240%. The current RAC for residential customers is 0.2261 cents/kWh so an increase of 0.3051 cents/kWh would be significant.

Riders are not intended to take all costs related to a specific component of rates and make them a separate, permanent component set out on the customer's bill. For example, while for the foreseeable future, Xcel and other utilities will likely have transmission riders, the specific projects included in the rider will change, as completed projects get incorporated into base rates in a subsequent rate case, and new projects get added to the rider. If there are no transmission projects not already incorporated in base rates, then there will be no transmission cost recovery charge on the bill at that point, though the rider could be used again in the future for new projects. The transmission rider does not take all transmission costs out or base rates and add them as a separate rate component.

Thus, Xcel's proposal would be a significant departure from current practice. Staff believes such an action may merit additional attention and further development before adoption. Accordingly, Staff recommends Decision Alternative 1, below.

This recommendation is in keeping with recent Commission precedent. When confronted with a similar proposition in the recent Minnesota Energy Resources Corporation rate case, the Commission rejected the proposal and instead adopted an agreement reached by the parties:

> MERC will continue using its existing CCRC calculation methodology, including the CCRC in base rates, and will maintain its CCRA in its current format.
>
> The Commission concurs with the parties that these issues have been properly resolved. The Commission therefore declines to adopt the Administrative Law Judge's findings and recommendations in paragraphs 580–82, which seem to anticipate removing CIP costs from base rates and recovering them through the CCRA. It would create administrative inefficiencies for one utility to use a CIP cost-recovery system different from those used by all other utilities and represent a departure from current practice of how the bulk of CIP costs are currently collected.[108]

Ordering Paragraph 9 in the MERC Order states: "MERC shall instead collect all of its test-year CIP expenses through the CCRC. … MERC shall continue its current CCRC calculation methodology by including the CCRC factor in its base distribution rate and maintain its CCRA factor in its current format."

---

[108] FINDINGS OF FACT, CONCLUSIONS, AND ORDER, in Docket No. G-011/GR-13-617, issued October 28, 2014, pages 11-12.

Conservation Cost Recovery Charge and the CIP Adjustment Factor Decision Alternatives

1. Reject the ALJ's recommendation and reject Xcel's proposal to zero out the CCRC from base rates and recover all CIP program costs through the monthly CIP Adjustment Factor. (Staff)

2. Adopt the ALJ finding that the record of the case supports the resolution of this issue as agreed to by Xcel and the DOC. (ALJ, Xcel, DOC)

3. If the Commission adopts the ALJ's finding on this issue, require Xcel to include an explanation of the increase in the CCRA in its customer notice of new rates. (Staff Alternate)

(Note: These decision alternatives correspond to alternatives VI, J (1 through 3) on p. 38 of the deliberation outline.)

Rate Shock

PUC Staff: Susan Mackenzie and Andrew Twite

U.S. Energy Services, Inc. and an ad hoc group of its industrial, commercial, and institutional customers (together the ICI Group) took issue with the Company's proposed rate increase. In paragraphs 633-635, the ALJ's report summarizes and refutes the ICI Groups' arguments (footnotes omitted):

> 633. The ICI Group has asked the Commission to deny the Company's proposed 10.4 percent rate increase over two years, as set forth in its initial filing, on the grounds that the Company's filing constitutes "rate shock." Technically, rate shock applies when a rate increase is so large that it results in a significant drop in usage, reflecting the unwillingness or inability of customers to pay for those services.
>
> 634. The ICI Group pointed out that this case is the fifth rate case filed by the Company in the past decade, and asserted that the cumulative effect of these rate cases, with the current request, represents a 48 percent increase in the cost of service over the pre-2005 annual revenue base. The ICI Group claims the current proposed rate increases drastically impact its group members because they must pay the increased cost of electric services for facilities operating around the clock with few opportunities to reduce costs.
>
> 635. The Administrative Law Judge concludes that the ICI Group's rate shock argument lacks merit. Under Minnesota law, a utility is entitled to recover reasonable, on-going costs associated with providing utility service. The determination regarding any request for a rate increase is based on the factors set forth in Minn. Stat. § 216B.16, subd. 6, including "the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service." These factors do not include rate shock. Thus, contrary to the ICI Group's assertion, rate shock alone is not a basis for denying the Company's proposed rate increases.

The ICI Group responded to the ALJ's arguments on pages 5 to 11 of its Exceptions.

Rate Shock Decision Alternatives

1. Adopt the ALJ's finding in paragraph 635 to deny the ICI Group's request to reject an increase to Xcel Energy's revenue requirement. (ALJ, Xcel)

2. Reject the ALJ's Finding in paragraph 635 and reject Xcel Energy's request to increase its revenue requirement. (ICI Group)

(Note: These decision alternatives correspond to alternatives VI, K (1 and 2) on p. 38 of the deliberation outline.)

Rate Design Issues—Resolved Issues Requiring Commission Action

PUC Staff: Susan Mackenzie and Andrew Twite

Windsource Rider

In its Direct testimony, the Department noted the Company had changed historical data in the Windsource tracker reports "without providing any justification, explanation, or even simply identifying such changes."[109] The Department recommended that the Commission require the Company not to change historical data in Windsource and FCA filings without identifying and providing a justification for the changes. The Department also raised concerns about confusing terminology used in the Windsource and FCA reports and recommended the Company clarify in each FCA and Windsource filing what costs are included in the Windsource Contract Payments.[110] The Company agreed to these recommendations.[111]

Windsource Rider Decision Alternative

1. Require Xcel Energy to not change historical data in Windsource and FCA filings without identifying and providing a justification for the changes. (Department, Xcel)

2. Require Xcel Energy to clarify in each FCA and Windsource filing what costs are included in the Windsource Contract Payments. (Department, Xcel)

(Note: These decision alternatives correspond to alternatives VI, L,1 (a and b) on p. 39 of the deliberation outline.)

Standby Service Tariff – Manner of Service

In his Direct testimony, MCC witness Schedin raised several issues with the Company's standby service and asked the Commission include said comments in its generic standby docket (Docket No. E002/M-13-315).[112] The Company agreed that Mr. Schedin's comments should be considered in docket 13-315.[113]

Standby Service Tariff Decision Alternative

1. Require Xcel Energy to address the issues raised by Mr. Schedin in his testimony in this case as part of the Commission's generic proceeding on standby service (in Docket No. E-999/CI-15-115). (MCC, Xcel).

(Note: This decision alternative corresponds to alternative VI, L, 2(a) on p. 39 of the deliberation outline.)

---

[109] Exhibit 408 (Ouanes Direct) at page 9.
[110] Ibid. at pages 12-13.
[111] Exhibit 103 (Peppin Rebuttal)at pages 42-43.
[112] Exhibit 340 (Schedin Direct) at pages 26-30.
[113] Exhibit 107 (Huso Rebuttal) at page 40.

Rate Design Issues—Resolved Issues and Undisputed Corrections

(Included in Attachment A to the ALJ Report)

(The following items are listed under decision alternative alternative VI, M on p. 39 on the deliberation outline.)

Low-Income Discount Program

In Rebuttal testimony, the Department noted that the Company's low-income discount program is only available to customers who are *receiving* LIHEAP assistance. The Department recommended that the program be made available for all customers who are *eligible* to receive LIHEAP.[114] Xcel and ECC took issue with recommendation, citing the expensive and burdensome administrative requirements and a conflict with the relevant Minnesota statute, which defines a "low-income" customer as one who receives LIHEAP assistance. In light of these comments, the Department withdrew its recommendation.

Level of Economic Development Discounts

In Direct testimony, the Department recommended reducing the amount of Competitive Response Rider economic development discounts to be recovered in base rates by half.[115] This would bring it into line with the level of actual 2013 economic development discounts. The OAG supported this recommendation.[116] The Company has agreed to the reduction.[117]

Nuclear Disposal Fees (2014)

In Direct testimony, the Department noted that the Company collects the US Department of Energy (DOE) spent nuclear disposal fees through the Fuel Clause Rider, and that the DOE reduced the disposal fee to zero effective May 16, 2014. The Department recommended the base cost of energy be reduced accordingly.[118] The Company has agreed to this adjustment.[119]

Time-of-Day Energy Charges/Energy Charge Credit

In its Direct testimony, the Company changed its methodology for calculating time of day energy charges, with the effect of slightly increasing the on-peak charge and decreasing off-peak charge. The Company also proposed an increase to its Energy Charge Credit, which would provide a larger credit to high load factor customers.[120] The Department endorsed these changes.[121]

---

[114] Exhibit 416 (Grant Rebuttal) at page 6.
[115] Exhibit 408 (Ouanes Direct) at pages 41-44.
[116] Exhibit 377 (Nelson Rebuttal) at page 19.
[117] Exhibit 107 (Huso Rebuttal) at pages 38-39.
[118] Exhibit 408 (Ouanes Direct) at pages 14-18.
[119] Exhibit 90 (Heuer Rebuttal) at pages 13-14.
[120] Exhibit 105 (Huso Direct) at pages 21-25.
[121] Exhibit 420 (Peirce Direct) at pages 22-24.

Firm Service Demand Charges

In its Direct testimony, the Company proposed to increase firm service demand charges.[122] No other party provided testimony on this issue.

Voltage Discounts

In its Direct testimony, the Company proposed to increase the demand charge discounts for the transmission voltage level.[123] No other party provided testimony on this issue.

Base Energy Charges for the C&I Demand Class

The Department supported the Company's proposed Base Energy Charges for the C&I Demand Class, as they "appear consistent with the results of the modified CCOSS recommended by the Department."[124]

DG Tariff Change

In his Direct testimony, MCC witness Schedin requested Xcel file with the Commission a request for changes to its Distributed Generation tariff. The Company filed the changes with the Commission in July 2014, and the Commission has since approved the modifications.[125]

Low-Income Renter Conservation Program

In its Direct testimony, the Energy CENTS Coalition (ECC) recommended the development of a low-income conservation program for renters living in smaller housing units (one- to four-unit buildings), citing a substantial need and opportunity for promoting energy efficiency among these customers.[126]

While all parties who responded to the ECC's request supported the goal of promoting energy efficiency for low-income renters, each of these parties raised issues with the ECC's proposal. The OAG argued the proposal lacks details and specificity.[127] The Company pointed to its Home Energy Savings Program and Multi-Family Energy Savings Program; each of these programs is open to low-income renters in smaller housing units.[128] The Department argued that these programs should be evaluated and utilized first before creating a new program.[129] The Company also stated that it is currently evaluating and redefining its conservation programs and design options for residents of multi-family buildings. The Company agreed to modify its CIP plan once the new program is fully developed.

---

[122] Exhibit 105 (Huso Direct) at pages 25-26.
[123] Ibid. at page 28.
[124] Exhibit 420 (Peirce Direct) at page 22.
[125] See Docket No. E-002/M-14-648, *In the Matter of the Petition of Northern States Power Company for Approval of Interconnection Tariff Changes*, Order Approving Interconnection Tariff Modifications, February 6, 2015.
[126] Exhibit 235 (Marshall Direct) at pages 1-31.
[127] Exhibit 377 (Nelson Rebuttal) at page 31.
[128] Exhibit 42 (Sundin Rebuttal) at pages 16-18.
[129] Exhibit 416 (Grant Rebuttal) at page 7.

In its Surrebuttal testimony, ECC agreed that the Department's CIP process is the "appropriate method for reviewing and implementing Xcel's forthcoming low-income rental conservation program."[130]

[130] Exhibit 240 (Marshall Surrebuttal) at page 4.