COMMERCE DEPARTMENT

May 29, 2018

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E001, 115, 140, 105, 139, 124, 126, 145, 132, 114, 6521, 142, 143/PA-14-322

Dear Mr. Wolf:

The Minnesota Department of Commerce, Division of Energy Resources (Department or the DOC) provides these comments in response to the Minnesota Public Utilities Commission's request for comments dated February 28, 2018 in this docket.

As discussed in the attached Comments, the Department recommends that the Commission find that the Southern Minnesota Energy Cooperative's (SMEC or Cooperative) **complied** with the Commission's Order dated June 15, 2015 in this proceeding. In addition, the Department recommends that the Commission find that SMEC Member Cooperatives' Class Cost of Service Studies **support** the proposed rate changes.

The Department is available to answer any questions that the Minnesota Public Utilities Commission may have.

Sincerely,

/s/ JOHN KUNDERT	/s/ ANGELA BRYNE	/s/ STEPHEN COLLINS
Financial Analyst	Financial Analyst	Rates Analyst

JK/AB/SC/ja
Attachment

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MN COMMERCE DEPARTMENT

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. E001, 115, 140, 105, 139, 124, 126, 145, 132, 114, 6521, 142, 143/PA-14-322

I. INTRODUCTION

On April 15, 2014, Interstate Power and Light Company (IPL) and Southern Minnesota Energy Cooperative (SMEC) filed for approval of the sale of IPL's Minnesota electric distribution system and assets, and the transfer of its service rights and obligations, to SMEC, which is an electric cooperative association of 12 rural electric cooperatives.[1]

In its June 8, 2015 Order Approving Agreement Subject to Conditions, the Minnesota Public Utilities Commission (Commission) found the proposed transaction to be consistent with the public interest if certain conditions were applied.

On February 28, 2018, the Minnesota Public Utilities Commission (Commission) issued a Notice of Comments (Notice) in this docket. The Commission's Notice stated the following:

> In its Order, the Commission retained jurisdiction to enforce the terms and conditions of a transitional 5-year rate plan (Rate Plan). The Rate Plan required SMEC and its Member Cooperatives to adopt IPL's retail rates for the first three years of the Rate Plan. For the subsequent two years, former IPL customers' rates would begin a transition period in which their rates will be merged with those of their Member Cooperative.
>
> SMEC's compliance filing was made ahead of the two-year transition period that will begin August 1, 2018.

[1] Minnesota Valley Electric Cooperative, of Jordan; Steele-Waseca Cooperative, of Owatonna; People's Energy Cooperative, of Oronoco; Tri-County Electric Cooperative, of Rushford; Freeborn-Mower Cooperative Services, of Albert Lea; BENCO Electric Cooperative, of Mankato; Brown County Rural Electrical Association, of Sleepy Eye; South Central Electric Association, of St. James; Redwood Electric Cooperative, of Clements; Federated Rural Electric Association, of Jackson; Nobles Cooperative Electric Association, of Worthington; and Sioux Valley Energy, of Colman, South Dakota.

The Commission identified three topics as open for comment in the Notice:

- Does Southern Minnesota Energy Cooperative's December 11, 2017 compliance filing and its subsequent revisions comply with the Commission's June 8, 2015 Order Approving Agreement Subject to Conditions (Order)?
- Do the Member Cooperatives' Class Cost of Service Studies support the proposed rate changes?
- Are there other issues or concerns related to this matter that the Commission should be aware of?

II. BACKGROUND

In its Order, the Commission listed six conditions[2]:

a. Annually, for three years following the proposed transaction's effective date, SMEC must provide actual weather-normalized annual revenue requirements for Interstate Power & Lights' (IPL) former service territory.
b. SMEC must provide a bill credit to IPL's former ratepayers if the actual weather-normalized annual revenue requirement in any year exceeds the forecasted annual revenue requirement by more than 2%.
c. For (a) and (b) above, the Commission adopts the implements programs as detailed in the Department of Commerce's (Department) March 12, 2015 letter.
d. Annually, for five years following the proposed transaction's effective date, SMEC must provide reliability information to the Commission for IPL's former service territory.
e. Within 90 days of this order, SMEC must make a compliance filing describing what reliability information will be provided, who will be preparing and filing the information, and when it will be filed each year.
f. IPL must return the remaining Alternative Transaction Adjustment to customers through a reduction in payments under the Wholesale Power Sales Agreement between SMEC and IPL.

Conditions (a) through (e) required SMEC to fulfill certain conditions within the initial three years of the five-year Transition Period. Condition (f) related to another IPL proceeding that resulted in an decrease in payments to IPL under the Wholesale Power Sales Agreement

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[2] *In the Matter of a Request for the Approval of the Asset Purchase and Sale Agreement Between Interstate Power and Light Company and Southern Minnesota Energy Cooperative,* ORDER APPROVING AGREEMENTS SUBJECT TO CONDITIONS at 9 (June 8, 2015).

between the Southern Minnesota Energy Cooperative (SMEC or Cooperative) and Interstate Power and Light (IPL).[3]

SMEC also made several additional commitments in its original filing related to the development of specific SMEC Member Cooperative Class Cost of Service Studies (CCOSS) and the proposed rates that derived from those CCOSS.[4]

A. CCOSS

Each SMEC Member Cooperative (MC) agreed to prepare a CCOSS that would determine the cost to service the Legacy Area, the Acquired Area, and the Combined Area. Specifically,

> The SMEC Member Cooperatives' Legacy Area and Acquired Area CCOSS's will reflect the area-specific costs for purchased power and distribution facilities. Other costs common to both the Legacy and Acquired Areas, such as Customer Accounting, Customer Service and Information, Sales, Administrative & General (A&G) and fixed costs related to General Plant, will be allocated to each area and then to each rate class based on appropriate allocation factors. The allocations will be made in a non-discriminatory manner. Finally, margin requirements in the Acquired Area will be determined in exactly the same manner as the Legacy Area. . . .
>
> Based on the results of these CCOSS's, each SMEC Member Cooperative will develop a plan to either: 1) continue to serve its Acquired Area and Legacy Area under separate cost based area rate structures, or 2) merge the rates of its Acquired Area and Legacy Area over time, or 3) some combination (i.e., a combination of some Acquired Area and Legacy Area based rates and some consolidated rates). The key to this determination will be the impact of the plan on the bills of the affected customers, . . .

SMEC provided the following table, (Table 1) that summarized the Member CCOSS results.[5]

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[3] *In the Matter of the Joint Petition for Approval of Transfer of Transmission Assets of Interstate Power and Light Company to ITC Midwest LLC.*
[4] IPL/SMEC's Initial Joint Filing at pages 24 through 26 (April 15, 2014).
[5] SMEC's Third Amended Compliance Filing at page 7 (April 6, 2018).

Table 1 – Overall Increases in Cost of Service by Customer by Service Area by Member Cooperative

Cooperative	Legacy Area	Acquired Area
BENCO	-5.18%	21.11%
Brown	-0.13	3.89%
Federated	-0.13%	21.42%
Freeborn Mower	-4.94%	8.82%
Minnesota Valley	2.83%	20.47%
Nobles	-1.67%	10.19%
Peoples	5.81%	1.06%
Redwood	1.04%	17.67%
Sioux Valley	-0.49%	24.90%
South Central	0.11%	18.61%
Steele-Waseca	-1.15%	13.80%
MiEnergy	1.22%	15.97%

B. APPORTIONMENT OF REVENUE RESPONSIBILITY AND RATE DESIGN

Beyond the CCOSS conditions, SMEC identified two conditions related to merging rates. First, SMEC stated that no rates would be merged unless the projected revenue produced by the Legacy Area and Acquired Area rates in question are within 5 percent of each other. Second, SMEC stated that no rate would be increased by more than 5 percent per year, excluding the operation of the Power Cost Adjustment (PCA) mechanism, to facilitate the merger of a Legacy Area and Acquired Area rate. Table 2 summarizes SMEC's interpretation of these criteria.[6]

[6] SMEC's Third Amended Compliance Filing at page 8 (April 6, 2018).

Table 2 – Overall Increases in Rates by Service Area by Member Cooperative

Cooperative	Year 1	Year 2
BENCO	Up to 5.00%	Up to 5.00%
Brown	Up to 3.89%	Up to 3.89%
Federated	Up to 5.00%	Up to 5.00%
Freeborn Mower	Up to 5.00%	Up to 5.00%
Minnesota Valley	Up to 5.00%	Up to 5.00%
Nobles	Up to 5.00%	Up to 5.00%
Peoples	Up to 1.06%	Up to 1.06%
Redwood	Up to 5.00%	Up to 5.00%
Sioux Valley	Up to 2.50%	Up to 5.00%
South Central	Up to 5.00%	Up to 5.00%
Steele-Waseca	Up to 5.00%	Up to 5.00%
MiEnergy (formerly Tri-County)	Up to 5.00%	Up to 5.00%

SMEC also provided information as to how rates that did not meet the two criteria listed above would be calculated during the August 2018 through July 2020 period. (This time frame is defined as the final two-years of the Transition Period).[7] First, each SMEC Member Cooperative will maintain separate rates for its Acquired Area and Legacy Area. Second, the rates for the Acquired Area and Legacy Area will be designed to recover, in total, the sum of the class revenue requirements for the Acquired Area, as determined by the CCOSS described above. The same approach will be used for the Legacy Area, with the total revenue requirements of the Acquired Area and Legacy Area being kept separate.

C. CREDIT TO ENERGY CHARGES

SMEC also provided a credit of $0.002/kWh to energy usage for the first three years of the Transition Period. The Cooperative explained that the credit was intended to reflect operational efficiencies, a lower borrowing rate and exemption from federal and state income taxes. This energy credit was estimated to be equal to an average rate decrease of approximately 2.2 percent in 2015.[8]

[7] SMEC acquired IPL's assets effect August 1, 2015. That date initiated the five-year period defined as the Transition Period.
[8] IPL/SMEC's Initial Joint Filing at page 23 (April 15, 2014).

The Department address these topics in the following section.

III. DEPARTMENT'S ANALYSIS

A. CONDITIONS (A) THROUGH (E) IN THE COMMISSION'S ORDER

On September 14, 2016, SMEC filed a variance report comparing forecasted to actual weather-normalized sales for the period from August 1, 2015 through July 31, 2016. The report identified a positive variance of 10,977 megawatt hours (MWh) of energy sales and a negative variance of $235,836 in non-energy related revenues for that time period.[9] The combination of higher-than-forecasted sales and lower-than-forecasted revenues resulted in lower-than-forecasted revenues per MWh. SMEC had forecasted its projected average net revenue (or cost from its ratepayers' perspective), of $67.69 per MWh. Its actual average net revenue for that time period was $66.54 per MWh, which was 1.70 percent lower than forecasted.

Since its actual weather-normalized annual revenue requirement was not more than 2 percent higher than forecasted, SMEC did not have to provide a bill credit to those former Interstate Power & Light (IPL) ratepayers for the first year of the initial three-year period.

On September 1, 2017, SMEC filed a variance report comparing the forecast to actual weather-normalized sales for the period from August 1, 2016 through July 31, 2017. The report identified a positive variance of 24,402 MWh of energy sales and a negative variance of $4,483,187 in non-energy related revenues for that same time period. Once again, the combination of higher-than-forecasted sales and lower-than-forecasted revenues resulted in lower-than-forecasted revenues per MWh.

SMEC had forecasted its projected average net revenue (again, cost from its ratepayers' perspective), of $72.23 per MWh. Its actual average net revenue for that time period was $64.59 per MWh, which was 12.60 percent lower than forecasted. Since its actual weather-normalized annual revenue requirement was not more than 2 percent higher than forecasted, SMEC does not have to provide a bill credit to those former IPL ratepayers for the second year of the three-year period.

For the two years in question, SMEC's annual revenue requirements were $4.7 million lower than it had forecasted. As a result, the threshold criterion in condition (b) that SMEC provide a bill credit to IPL's former ratepayers if the actual weather-normalized annual revenue requirements in any year exceed the forecasted annual revenue requirement by more than 2 percent in the Commission's Order was not met and no refunds were required during the first two years of the Transition Period.

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[9] The Department defines a positive variance for energy sales as being higher than forecasted and a negative variance for cost as being lower than forecasted in this instance.

The Department anticipates that SMEC will file its third and final compliance filing related to these conditions in mid-September 2018. The Department will provide the Commission with that additional information at that time.

The Department concludes that SMEC has complied with conditions (a) through (c) of the Commission's Order to date.

Conditions (d) and (e) of that same Order delineate SMEC's responsibilities relative to reliability reporting. On February 16, 2017, SMEC filed its 2016 Annual Reliability Report in compliance with the Commission's Order. The Cooperative also provided its 2017 Annual Reliability Report March 20, 2018.

The Department reviewed SMEC's 2017 Annual Report to assess compliance with the Commission's Order. The Department used information from past annual reports from SMEC and IPL to facilitate the analysis regarding SMEC's performance.

1. Reliability

The Cooperative measured its reliability using industry standard metrics of the Customer Average Interruption Duration Index (CAIDI), System Average Interruption Duration Index (SAIDI), and System Average Interruption Frequency Index (SAIFI) as defined by the standard Institute of Electrical and Electronics Engineers (IEEE) 1366 definition.10 The below indices are for SMEC's service territory as a whole:

SAIDI (average number of minutes any customer is without power) = 62.39
SAIFI (average number of times any customer is without power) = 0.77
CAIDI (average minutes per outage for customers that lose power) = 81.20

The Department notes that no reliability goals were set for 2017, as SMEC is required to provide the information only for comparison purposes to IPL's reliability.

2. Major Events Days

Minnesota Rules Electric Utility Standards 7826.0500, subp. 1.D requires, "an explanation of how the utility normalizes its reliability data to account for major storms." IPL previously used IEEE 1366 standard (2.5 beta method). SMEC stated that it will have difficulty defining a major event during the five years of reliability reporting to the Commission. The Cooperative would prefer to follow IEEE 1366 standard to define a major event; however, the calculation cannot be computed, as SMEC does not have five years of daily SAIDI data. As an alternative, the Cooperative will note when major events occur at a specific SMEC Member Cooperative (MC) as

[10] IPL used the same methodology to report its reliability data when it owned regulated operations in Minnesota.

this information would indicate that customers in the former IPL service territory are most likely affected by the MC's major event.

SMEC's overall reliability indices do not include major events that occurred during 2017. In 2017, the SMEC cooperatives did experience multiple major events beginning with thunderstorms and high winds that occurred on March 6, 2017, which affected Freeborn-Mower Cooperative Services and Steele-Waseca Cooperative Electric. On May 17, 2017, the City of Stewartville had a major transmission outage that occurred the morning of May 17, 2017. Additionally, severe thunderstorms affected the area that afternoon resulting in People's Energy Cooperative to have a Major Event Day. Additional thunderstorms occurred in June and July affecting members of Freeborn-Mower Cooperative Services, Nobles Electric Cooperative, and Steele-Waseca Cooperative Electric.

The Department concludes that SMEC complied with the Commission's June 8, 2015 Order for 2016 and 2017.

IPL's former ratepayers brought a certain history regarding reliability when they became member of the different MCs. Below are tables listing the historical reliability indices, both before and after the transfer of ownership from IPL to SMEC. The indices between the companies will not be completely comparable, due to the lack of contiguous historical data for SMEC, the consolidation of two work centers under IPL to one under SMEC, and differences in determining major event days. However, the Department provides this comparison to build a general picture of reliability trends for IPL's former customers.

Actual performance measures for IPL and SMEC since 2013 are as follows:

	IPL – Albert Lea			IPL – Winnebago		
Year	SAIDI	SAIFI	CAIDI	SAIDI	SAIFI	CAIDI
2013	136.14	1.16	117.51	86.44	0.76	113.54
2014	72.50	0.83	87.50	95.30	0.89	107.50
2015: Jan - July	49.40	0.42	117.80	88.50	0.67	132.00

	SMEC		
Year	SAIDI	SAIFI	CAIDI
2015: Aug - Dec	15.02	0.27	55.75
2016	71.08	0.82	87.06
2017	62.39	0.77	81.20

The indices provided for 2015 are invalid, since reliability was measured over two partial years. However, the two years reported by IPL before 2015 and the two years reported by SMEC after 2015 give an initial indication that, at a minimum, reliability is not declining.

While IPL operated regulated electric facilities in Minnesota, it struggled to meet its reliability goals, particularly in its Albert Lea work center. The Department regularly took issue with IPL's reliability, and in the last full-year annual report, the Department wrote the following in its Comments,[11]

> As in past reports, IPL's annual explanations for its continuing struggle to attain its reliability goals generally focus on what it has done, or will do, to fix the specific incident or incidents it considered the main reason for its failure to meet the goals, and/or describe non-preventable events as contributing factors. **Overall, IPL's performance has generally remained steady or worsened since 2004**, indicating that the action steps described may have had limited, or insignificant, impact on overall reliability performance. [The] Table below shows how many of its six annual goals IPL has met since 2004. [Emphasis added.]

Table 3 – IPL's Reliability Performance 2004 through Mid-2015

	Winnebago			Albert Lea		
	SAIDI	SAIFI	CAIDI	SAIDI	SAIFI	CAIDI
2004	Yes	Yes	No	No	No	No
2005	No	No	No	No	No	No
2006	Yes	Yes	Yes	No	Yes	No
2007	No	No	No	Yes	No	Yes
2008	Yes	Yes	No	No	No	No
2009	Yes	Yes	No	Yes	No	Yes
2010	No	No	No	No	No	No
2011	No	Yes	No	No	Yes	No
2012	No	No	No	Yes	No	Yes
2013	No	Yes	No	No	No	No
2014[12]	No	Yes	No	Yes	Yes	No

[11] The Department's Comments issued June 30, 2018 in Docket No. E001/M-14-282.
[12] Data for 2014 was added to this table for the sake of completeness in this analysis.

The information in Table 3 suggests that SMEC did not acquire a distribution system that was improving in terms of its reliability. Thus, the Department considers any improvement, even in average reliability factors, to be a positive development. Currently, it appears that SMEC is providing reasonably reliable service to former IPL customers in Minnesota. In addition, the Department concludes that SMEC has complied with conditions (d) and (e) of the Commission's Order.

B. SMEC'S ADDITIONAL COMMITMENTS

The Cooperative described its approach for developing the Member Cooperative's CCOSS as follows. SMEC retained consultants from the Cooperative Finance Corporation (CFC) to perform the CCOSSs for the 12 individual cooperatives. Department staff met with SMEC and CFC representatives so that CFC staff could walk through the CCOSS and explain their overall approach. A document summarizing CFC's CCOSS is included as Attachment A.

CFC's CCOSS follows the typical steps prescribed in widely used National Association of Regulatory Utility Commissioners' Electric Utility Cost Allocation Manual. First, CFC's CCOSS groups costs into different functions such as production, transmission, and distribution. Second, it classifies costs according to whether they were caused by peak demand, overall energy requirements, or the number of customers. Third and last, it allocates costs using different factors that attempt to reflect as accurately as possible how the costs were caused. For example, CFC allocates energy-related costs using kilowatt-hours.

The Department reviewed CFC's methods and concludes that they are reasonable. For example, CFC adopted the Department's long-preferred practice of classifying distribution costs into either demand-related or customer-related components, using the well-established "minimum-size" methodology. The Department also reviewed CFC's CCOSS calculations, provided as spreadsheets in response to an information request, and did not identify any errors. As a result, the Department concludes that SMEC fulfilled this commitment.

C. APPORTIONMENT OF REVENUE RESPONSIBILITY

The Commission has identified apportionment of revenue responsibility as the second step of a three-step rate-setting process, which includes: 1) developing unit costs, 2) apportioning revenue requirements by class and 3) designing rates.

The Department asked SMEC to "confirm that the unit costs developed in the different cooperatives' CCOSS Models are the basis for the proposed rates identified in the filing." SMEC replied:

> Yes, the unit costs developed in the different cooperatives' CCOSS Models are the primary basis for the proposed rates identified in

> SMEC's compliance filing. It is important to clarify however, that while unit costs reflected in the CCOSS results are the primary consideration used in the development of the proposed rates, unit costs can never be the sole consideration used in ratemaking. This is because the cooperatives must balance a variety of objectives and factors when developing rates. Relevant objectives and factors include, among other considerations, the Commission-approved Rate Plan, revenue needs, bill impacts, member communications, gradualism, rate consolidation and integration goals, and of course, the CCOSS results and unit costs identified herein. For this reason, the rate design for all customer classes is not exclusively tied to the unit costs reflected in the CCOSS for all cooperatives. Rather, each cooperative's board balanced all of the foregoing objectives and factors, including the CCOSS results, when making their final ratemaking decisions for the proposed rates.[13]

The Department concludes that unit costs are a primary consideration for rate setting and that the CCOSS results are used appropriately to apportion revenue responsibility.

As to the reasonableness of the MC's proposed rate increases, Table 4 compares the proposed rate increases in the acquired area by MC in SMEC's recent filing, its response to DOC IR no. 67 and the CCOSS results for the same area and MC.

Table 4 – Comparison of Proposed Rate Increases and CCOSS Results for Acquired Areas by Member Cooperative

Cooperative	Filing - Year 1 Proposed Increase	DOC IR #67 Response - Year 1 Proposed Increase	Overall Increase CCOSS Supports
BENCO	Up to 5.00%	5.00%	21.11%
Brown	Up to 3.89%	3.80%	3.89%
Federated	Up to 5.00%	5.00%	21.42%
Freeborn Mower	Up to 5.00%	5.31%	8.82%
Minnesota Valley	Up to 5.00%	4.98%	20.47%
Nobles	Up to 5.00%	4.97%	10.19%
Peoples	Up to 1.06%	1.06%	1.06%
Redwood	Up to 5.00%	5.00%	17.67%
Sioux Valley	Up to 2.50%	0.00%	24.90%
South Central	Up to 5.00%	5.00%	18.61%
Steele-Waseca	Up to 5.00%	5.31%	13.80%
MiEnergy (formerly Tri-County)	Up to 5.00%	4.49%	15.97%

[13] A copy of this information request response is included as Attachment B.

The Member Cooperative's proposed first year apportionment of revenue responsibility increases appear to be reasonable, as the amounts are all equal to or lower than the percentage increases shown in the results of the respective CCOSS. The CCOSS results from nine of the twelve Member cooperatives support potentially much larger increases. The Department considers these increases reasonable and largely in compliance with the additional commitments, that SMEC identified in its original filing.[14]

D. RATE DESIGN

Technically, rate design involves developing specific rates that when multiplied by the forecasted billing determinants are expected to allow the utility to recover the amount of annual revenue that is equal to the particular rate class' revenue requirement apportionment. SMEC did not provide rate design information by class in its compliance filing. Rather, it provided what the Department would define as bill impacts, the percentage change in the average monthly bill by class.

As support for this characterization, the Department notes SMEC's response to Department Information Request no. 67 that asked: "Please provide an analysis of the average monthly bill under current and proposed base rates for each customer class by cooperative for the Acquired area." In its response, SMEC provided a series of tables by Member Cooperative that included customer class, average monthly bill under current and proposed rates, the nominal increase in the monthly bill, the percentage increase in the same and the nominal effect of the $0.002/kWh credit.[15] Table 5 summarizes this information for the Residential Customer Class.

Table 5 – Summary of Residential Average Monthly Bill by Cooperative

Cooperative	Current Rates ($/month)	Proposed Rates ($/month)	Nominal Increase ($/month)	Percentage Increase
BENCO	$87.36	$91.72	$4.37	5.00%
Brown	$90.84	$94.30	$3.45	3.80%
Federated	$85.50	$89.77	$4.27	5.00%
Freeborn Mower	$73.88	$77.80	$3.92	5.31%
Minnesota Valley	$74.86	$78.59	$3.73	4.98%
Nobles	$88.55	$92.95	$4.40	4.97%
Peoples	$76.93	$77.75	$0.82	1.07%
Redwood	$85.91	$90.21	$4.30	5.00%
Sioux Valley	$99.92	$99.92	$0.00	0%
South Central	$88.26	$92.68	$4.42	5.00%
Steele-Waseca	$73.88	$77.80	$3.92	5.31%
MiEnergy	$101.86	$106.44	$4.58	4.49%

[14] While the Department notes that Freeborn-Mower and Steele-Waseca's increases of 5.31% respectively appear to be higher than the 5.00% threshold SMEC identified, those increases could be "rounded-down to 5.0 percent".
[15] A copy of SMEC's response is included as Attachment C.

The nominal increases for an average residential customer range from $0.00 to $4.58 per month. The percentage increases range from a low of 0.0 percent to a high of 5.3 percent. As noted previously, the proposed rate increases appear to be reasonable given the results of the respective CCOSS. The Department also notes that these former IPL ratepayers have not experienced an increase in base rates since IPL's last general rate case in 2010. As a point of reference, the Producer Price Index for the utility industry increased 6.2 percent between January 1, 2010 and April 1, 2018.[16] While this index considers a much broader population of inflation-related costs than simply electric distribution service, it is indicative of a trend of cost increases for providing utility service over the past eight years across the United States. The former IPL distribution network would have to demonstrate unusual cost characteristics to have run counter to this trend.

Relative to a baseline 6.2 percent increase for the period from 2010 through early 2018, the first-year increases identified by the MC's appear to be reasonable.

As noted previously, former IPL ratepayers' monthly bills will also increase due to expiration of the 2 mill/kWh credit that has been provided during the first three years of the Transition Period. Table 6 sums the proposed increases in base rates and the nominal amount identified as the change due to the removal of the 2 mill/kWh credit to determine the bill impact on an average residential customer by MC.

The nominal increases vary from $2.04 to $6.14 per month for an average residential customer. The percentage changes vary from 2.04% to 7.09% for the same class and usage.

Table 6 – Summary of Residential Average Monthly Bill plus Effect of Removal of the 2 Mill Credit by Cooperative

Cooperative	Current Rates ($/month)	Proposed Rates Plus 2 Mill Credit ($/month)	Nominal Increase ($/month)	Percentage Increase
BENCO	$87.36	$92.75	$5.39	6.17%
Brown	$90.84	$96.05	$5.21	5.74%
Federated	$85.50	$91.30	$5.80	6.78%
Freeborn Mower	$73.88	$79.12	$5.24	7.09%
Minnesota Valley	$74.86	$79.95	$5.09	6.80%
Nobles	$88.55	$94.60	$6.05	6.83%
Peoples	$76.93	$79.09	$2.16	2.81%
Redwood	$85.91	$91.75	$5.84	6.8%
Sioux Valley	$99.92	$101.96	$2.04	2.04%
South Central	$88.26	$94.27	$6.01	6.81%
Steele-Waseca	$73.88	$79.12	$5.24	7.09%
MiEnergy	$101.86	$108.00	$6.14	6.03%

[16] https://fred.stlouisfed.org/series/PCU221221.

The prospect of an increase of an over 7 percent in an average residential customer's bill for the period August 2018 through July 2019 for two of the MC's (Freeborn-Mower and Steele Waseca) is somewhat concerning.[17]

Low-income households are those most likely to be financially inconvenienced by a five to seven percent increase in their electric bills. Department Information Request no. 68 asked:

1) Please identify which SMEC cooperatives have low-income assistance programs.
2) Are customers in the Acquired Areas eligible for those low-income programs?
3) Could the member cooperatives' low-income programs help mitigate rate increases resulting from the merger of former IPL rate schedules with the specific SMEC cooperative's existing rate schedules for former IPL customers?
4)

The Cooperative noted in its response:

> All of the SMEC member cooperatives administer, participate in, and/or contribute to low-income assistance programs. These programs are available to qualifying Acquired Area members who meet the various low-income assistance programs' criteria in the same manner that they are available to qualifying Legacy Area members that meet such criteria.

It appears that former IPL low-income households will have the ability to access financial assistance for their electric bills if necessary.

The question in subpart (3) addressed the specific situation where MC's might propose to merge rate classes for the Legacy and Acquired areas. SMEC noted:

> Yes, the SMEC member cooperatives believe that their low-income assistance programs can help mitigate rate increases that may result from the merger of the former IPL rate schedules with the specific SMEC cooperatives' existing rate schedules after the completion of the Transition Period. Such mitigation will be predominantly through assistance that low income programs provide qualifying members with respect to paying their utility bills. The cooperatives have found that such assistance has the added

[17] An additional 5 percent increase for the August 2019 through July 2020 for these same two MC's would result in an overall increase to the average residential bill of 12.5 percent over a 2-year period.

> benefit of reducing the overall number of uncollectible accounts, which in turn reduces costs for all members.
>
> It is also likely that energy efficiency measures funded by individual cooperatives will mitigate Acquired Area members' energy bills. Such measures include assistance with weatherization, lighting, and high-efficiency appliance upgrades intended to improve members' daily living while reducing out-of-pocket expenses that would otherwise be spent on increased energy usage. Any mitigation of household energy costs will be dependent on the specific project and the individual member's home energy consumption patterns.

Given SMEC's response to DOC IR no. 68, the Department believes that those former IPL ratepayers most likely to be inconvenienced financially due to the proposed increases in the average monthly bill for residential customers could receive financial assistance for paying those additional costs. While this alternative is less than perfect, it will exist for low-income former IPL ratepayers who request it.

E. RESPONSE TO COMMISSION TOPICS

1. *Does Southern Minnesota Energy Cooperative's December 11, 2017 compliance filing and its subsequent revisions comply with the Commission's June 8, 2015 Order Approving Agreement Subject to Conditions (Order)?*

Yes. The Department's analysis concludes that SMEC fulfilled the six conditions listed in the Commission's Order to date.

2. *Do the Member Cooperatives' Class Cost of Service Studies support the proposed rate changes?*

Yes. The Department concludes that the CCOSS methodologies are reasonable and that the respective results supported the proposed rate increases.

3. *Are there other issues or concerns related to this matter that the Commission should be aware of?*

Yes. The Department noted that the expiration of the 2 mill/kWh credit for usage under the Power Cost Adjustment would increase residential customer bills in the first year of the 2 year Transition Period by an additional 2 percent. As a result, residential customers served by Freeborn-Mower and Steele-Waseca could see increases in their average monthly bills of over 7 percent beginning in August 2018 and potentially ending in July 2019 with another 5 percent increase scheduled for the August 2019 through July 2020 time period.

The Department requested additional information regarding the availability of low-income assistance programs for former IPL customers. SMCE identified several low-income options for former IPL customers who seek financial assistance.

While the Department is confident that the MCs will provide as much financial assistance as possible for those former IPL customers that are eligible for assistance, the Department is also concerned about the extent of the second increase in 2019. The Department requests that SMEC discuss potential rate mitigation strategies for the Freeborn Mower and Steele-Waseca MC's in its Reply Comments.

The Department also reviewed the MC's reliability statistics for the two full years (2016-2017) that SMEC was responsible for that function in IPL's former Minnesota service territory. While two years is not an adequate time frame to develop a clear picture of the MC's reliability efforts, the results from those two years suggest that reliability is as good as or better than it was under IPL's watch.

IV. RECOMMENDATIONS

The Department recommends that the Commission find that SMEC complied with the conditions listed in the Commission's June 8, 2015 Order in this proceeding. In addition, the Department recommends that the Commission find that the SMEC Member Cooperative CCOSS results support the MC's proposed rate increases for period from August 2018 through July 2019. Finally, the Department requests that SMEC discuss the potential for mitigating the proposed 5 percent rate increases identified for Freeborn Mower and Steele Waseca in the final year of the Transition Period (August 2019 through July 2020).

/ja

OVERVIEW GUIDE FOR CFC'S ELECTRIC FULLY ALLOCATED CLASS COST OF SERVICE STUDY

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION'S REGULATORY AFFAIRS

OVERVIEW

The approach most often used by regulators has been to measure the total costs incurred in conducting operations over a test year and to fix rates that will produce revenues to match the costs of that period. The term "cost of service" addresses the total costs incurred in providing service during the test year and measures the costs to be recovered through rates at the sales level of the test year. The purpose of the electric Class Cost of Service (COSS) is then to allocate both joint and common costs to the designated classes of service. The COSS also assigns direct costs by specific assignment of those costs to classes that have caused those costs (e.g. a specifically assigned substation), that may be associated with providing service to a particular customer from a specific class of service. The objective of the COSS is to make these cost allocations and assignments based on identifiable usage (e.g. kWh energy requirements, customer related costs, and kW capacity requirements), which are the drivers of the costs. The COSS may be separated into four basic components, or groups:

- O&M
- Depreciation
- Taxes (income related, property taxes and other taxes)
- Capital costs

The total of these four components produces the test year allocated cost of service which equals the total revenue requirement expressed by the following formula:

Revenue Requirement = Operating Expenses[1] + (Rate of Return * Rate Base)

MAJOR STEPS OF THE CLASS COST OF SERVICE STUDY

A class cost of service study begins with detailed jurisdictional revenue requirements. At a high level, the COSS process consists of the following three (3) basic steps:

- Functionalization – The identification of each cost element as one of the basic utility service "functions" (e.g. generation, transmission, distribution and customer).

- Classification – The classification of the functionalized costs based on the billing component/determinant that each is associated with (e.g. kWs of capacity, kWhs of energy or number of customers).

[1] Operating expenses = O&M + Depreciation + Taxes.

- Allocation – The allocation of the functionalized and classified costs to customer classes, based on each class's respective service requirements (e.g. kWs of capacity, kWhs of energy and the number of customers, expressed in terms of a percentage of the total jurisdiction requirement).

Step 1: Functionalization

Functionalization is the process of associating each of the numerous detailed elements of the total revenue requirement with functions (and sometimes sub-functions) of the electric utility system. Costs must be first functionalized because each class's service requirement tends to have different relative impacts on each service function. As such, it is necessary to develop separate sub-parts of the total revenue requirement for each function (and sometimes sub-function). The 4 basic functions and the associated sub-functions are shown in the table below:

Function	FERC Accounts	Sub-Function
Generation	120, 310-346, 500-557	Energy-related
		Capacity-related
Transmission	350-359, 560-579	None
Distribution	360-368, 580-598	Distribution Capacity
		Primary Distribution System "Capacity."
		Secondary Capacity Distribution System "Capacity."
Customer	360-369, 580-598, 901-916	Customer portion of the Primary and Secondary Systems
		Energy Services

Generation Cost Stratification. Stratification is the term used to identify the part of the COSS process used to separate or stratify fixed generation costs into the necessary capacity-related and energy related sub-functions. The capacity-related portion of the fixed costs of owned generation is based on the percent of total fixed costs of each generation type that is equivalent to the cost of a comparable peaking plant (the generation source with the lowest capital cost). The percent of total generation costs that exceeds the cost of a comparable peaking plant are sub-functionalized as energy-related. This second portion of the fixed generation costs is energy-related because these costs are in excess of the capacity-related portion and as such were not incurred to obtain capacity but rather were incurred to obtain the lower cost energy that such plants can produce.

Step 2: Cost Classification

The second step in the COSS process is to classify the functionalized costs as being associated with a measurable customer service requirement which gives rise to the costs. The 3 principle service requirements or billing components are:

- Demand – Costs that are driven by customers' maximum kilowatt ("kW") demand.
- Energy – Costs that are driven by customers' energy or kilowatt-hours ("kWh") requirements.
- Customer – Costs that are related to the number of customers served.

The table below shows how each of the functional and sub-functional costs was classified:

Function/Sub-Function	Cost Classification		
	Demand	Energy	Customer
Summer Capacity-Related Fixed Generation	X		
Energy-Related Fixed Generation		X	
Transmission	X		
Distribution Substations	X		
Primary Transformers	X		
Primary Lines	X		X
Secondary Lines	X		X
Secondary Transformers	X		X
Service Drops	X		X

Function/Sub-Function	Cost Classification		
	Demand	Energy	Customer
Metering			X
Customer Services			X

As shown in the table above, primary lines, secondary lines, secondary transformers and service drops are classified as both “demand” and “customer” related costs. Costs of these subfunctions are driven by both the number of customers on the distribution system and the capacity requirements they place on the system. Two methods that are mentioned in the NARUC manual for performing this cost separation are the Minimum Distribution System (MDS) method and the Minimum/Zero Intercept method. CFC employs the minimum distribution system methodology.

Step 3: Cost Allocation to Customer Class (Assignment of Costs to Customer Classes)

The third step in the COSS process is allocation, which is the process of assigning (allocating or directly assigning) functionalized and classified costs to customer classes. Generally, cost assignment occurs in one of 2 ways:

- Direct Assignment - A small but sometimes important portion of costs can be directly assigned to a specific customer of a particular customer class, because these costs can be exclusively identified as providing service to a particular customer. Examples of costs that are directly assigned include:
    - Customer-dedicated transmission radial lines or dedicated distribution substations (e.g. street lighting facility costs)

- Allocation - Most electric utility costs are incurred in common or jointly in providing service to all or most customers and classes. Therefore, allocation methods have to be developed for each functionalized and classified cost component. The allocation method is based on the particular measures of service that is indicative of what drives the costs.

Class allocators (sometimes called “allocation strings”) are simply a “string” of class percentages that sum to 100%. There are 2 types of allocators:

- External Allocators –These are the more interesting allocators that are based on data from outside the COSS model (e.g. load research data, metering and customer service-related cost ratios). In general, there are several types of external allocators:
    - Capacity – related (sometimes referred to as Demand) allocators such as:
        - System coincident peak (CP) responsibility or class contribution to system peak (1CP, 4CP or 12CP)
        - Class peak or non-coincident peak of Individual customer maximum demands

Energy-related allocators such as:

- o kWh at the customer (kWh sales) o kWh at the generator (kWh sales plus loses) o kWh energy, weighted by the variable cost of the energy in the hour it's used
- o Customer-related allocators o Number of customers
- o Weighted number of customers, where the weights are based on cost of meters, billing, meter-reading, etc.

- Internal Allocators – These are allocators based on combinations of costs already allocated to the classes using external allocators. These internal allocators are used to assign certain costs, which are most appropriately associated with and assigned to classes by some combination of other primary service requirements, such as kWs demand, kWhs of energy or the number of customers.

Customer Class Definitions

Because customer usage characteristics are frequently quite different, it is necessary to allow for different classes where the customers of the class have similar cost and service characteristics.

Organization of the COSS Model

The COSS model consists of numerous worksheets which show costs by customer class in total and by class. Listed below are important calculations that are part of the COSS model.

Cost of Capital. The weighted average cost of capital represents the weighted cost of debt and equity as shown below. The model provides for preferred stock; however very few cooperatives issue preferred stock.

			CapitalizationWeighted	
		Capitalization(%)CostCost		
1	Debt$9,271,55497.26%3.99%3.88%			
2	Equity$261,2262.74%8.45%0.23%			
3	Total$9,532,780100.00%4.11%			

It is shown in the model on page 1.

RETURN ON COMMON EQUITY				8.45%
OVERALL RATE OF RETURN				4.11%
CAPITALIZATION:				
	OUTSTANDING	EFFECTIVE RATE	COMPOSITE	
DBT	$9,271,554	3.99%		3.88%
PRF	$0	0.00%		0.00%
CMN	$261,226	8.45%		0.23%

Many cooperatives use coverage ratios (e.g. TIER or DSC) to illustrate their cash requirements when setting a revenue requirements. Doing such fails to reflect an adequate return on equity (ROE) because: (1) coverage ratios typically do not reflect the cash requirement to return patronage capital over time, and (2) does not reflect the fact that the majority of cooperatives have significant equity. When cooperatives were first created, they had only a minimal amount of equity. Today the average amount of equity exceeds 47% of capitalization.

Rate Base Calculation. Rate Base = Original Cost Gross Plant in Service – Accumulated Depreciation – Accumulated Deferred Income Taxes + CWIP + Other Additions. These are shown by line item below. The vast majority of electric cooperatives are tax exempt with respect to income taxes; hence, there are no accumulated deferred income taxes.

Throughout the model, the allocator for each line is illustrated in the "All" column. Likewise if the model creates an allocator for subsequent use, it is shown in the "Out" column.

Gross Plant

				****ELECTRIC GROSS PLANT****				
LINE NO.	DESCRIPTION	ALL	OUT	TOTAL COMPANY	RESIDENTIAL	SEASONAL	GENERAL SERVICE	LARGE POWER
1	TOTAL PRODUCTION PLANT	D1A	GPP	$0	$0	$0	$0	$0
	TRANSMISSION PLANT							
2	POWER PLANT EQUIP	D1A		$0	$0	$0	$0	$0
3	LARGE POWER SERVICE EQUIP	DA1		$0	$0	$0	$0	$0
4	OTHER DIST IN ACCT 353	D2A		$0	$0	$0	$0	$0
5	ALL OTHER TRANSMISSION	D1B		$0	$0	$0	$0	$0
6	TOTAL TRANSMISSION PLANT	GPT	GPT	$0	$0	$0	$0	$0
	DISTRIBUTION PLANT							
7	PRIMARY DEMAND RELATED	D4A		$5,806,204	$3,817,124	$349,655	$1,524,613	$99,901
8	SECONDARY DEMAND RELATED	D3A		$2,286,461	$1,503,168	$137,693	$600,387	$39,341
9	CUSTOMER RELATED	C4A		$5,204,536	$2,864,389	$1,212,708	$849,527	$1,579
10	SUB-TOTAL DISTR PLANT		SGD	$13,297,202	$8,184,682	$1,700,056	$2,974,527	$140,821
11	LIGHTING SPECIFIC	LDE		$0	$0	$0	$0	$0
12	TOTAL DISTRIBUTION PLANT	GPD	GPD	$13,297,202	$8,184,682	$1,700,056	$2,974,527	$140,821
	GENERAL AND INTANGIBLE PLANT							
13	PRODUCTION RELATED	GPP		$0	$0	$0	$0	$0
14	TRANSMISSION RELATED	GPT		$0	$0	$0	$0	$0
15	DISTRIBUTION RELATED	GPD		$189,861	$116,863	$24,274	$42,471	$2,011
16	CUST ACCT/SERV & INFO/ SALES RELATED	C2A		$54,098	$29,775	$12,605	$8,830	$16
17	TOTAL GENERAL & INTANGIBLE PLANT	GPG	GPG	$243,959	$146,638	$36,879	$51,301	$2,027
18	TOTAL GROSS PLANT IN SERVICE	GPR	GPR	$13,541,161	$8,331,320	$1,736,935	$3,025,828	$142,848

Created Allocator for Subsequent use

Allocator used for individual line item.

The model allows for a wide range of demand allocator methodologies when appropriate to use. We use an average 12 month CP or NCP unless there are good reasons to deviate.

Accumulated Depreciation

LINE NO.	DESCRIPTION	ALLOC	OUT	TOTAL COMPANY	RESIDENTIAL	SEASONAL	GENERAL SERVICE	LARGE POWER
					********ELECTRIC PLANT********			
					ACCUMULATED DEPRECIATION			
1	TOTAL PRODUCTION PLANT	D1A	DPP	$0	$0	$0	$0	$0
	TRANSMISSION PLANT							
2	POWER PLANT EQUIP	D1B		$0	$0	$0	$0	$0
3	LARGE POWER SERVICE EQUIP	DA1		$0	$0	$0	$0	$0
4	OTHER DIST IN ACCT 353	D2A		$0	$0	$0	$0	$0
5	ALL OTHER TRANSMISSION	D1A		$0	$0	$0	$0	$0
6	TOTAL TRANSMISSION PLANT	DPT	DPT	$0	$0	$0	$0	$0
	DISTRIBUTION PLANT							
7	PRIMARY DEMAND RELATED	D4A		$2,167,098	$1,424,698	$130,504	$569,044	$37,287
8	SECONDARY DEMAND RELATED	D3A		$853,395	$561,041	$51,392	$224,087	$14,683
9	CUSTOMER RELATED	C4A		$1,942,532	$1,069,100	$452,629	$317,076	$589
10	SUB-TOTAL DISTR PLANT		SDD	$4,963,025	$3,054,839	$634,525	$1,110,207	$52,559
11	LIGHTING SPECIFIC	LDE		$0	$0	$0	$0	$0
12	TOTAL DISTRIBUTION PLANT	DPD	DPD	$4,963,025	$3,054,839	$634,525	$1,110,207	$52,559
	GENERAL AND INTANGIBLE PLANT							
13	PRODUCTION RELATED	GPP		$0	$0	$0	$0	$0
14	TRANSMISSION RELATED	GPT		$0	$0	$0	$0	$0
15	DISTRIBUTION RELATED	GPD		$71,712	$44,141	$9,168	$16,042	$759
	CUST ACCT/SERV & INFO/							
16	SALES RELATED	C2A		$20,433	$11,246	$4,761	$3,335	$6
17	TOTAL GENERAL & INTANGIBLE PLANT	DPG	DPG	$92,145	$55,387	$13,929	$19,377	$765
18	TOTAL ACCUMULATED DEPRECIATION	DPR	DPR	$5,055,170	$3,110,226	$648,454	$1,129,584	$53,324

Net Plant

				*******ELECTRIC NET PLANT*******				
LINE		CONTROL		TOTAL		GENERAL	LARGE	
NO.	DESCRIPTION	ALLO	OUT	COMPANY	RESIDENTIAL	SEASONAL	SERVICE	POWER
				--				
1	TOTAL PRODUCTION PLANT	D1A	NPP	$0	$0	$0	$0	$0
	TRANSMISSION PLANT							
2	POWER PLANT EQUIP	D1B		$0	$0	$0	$0	$0
3	LARGE POWER SERVICE EQUIP	DA1		$0	$0	$0	$0	$0
4	OTHER DIST IN ACCT 353	D2A		$0	$0	$0	$0	$0
5	ALL OTHER TRANSMISSION	D1A		$0	$0	$0	$0	$0

6	TOTAL TRANSMISSION PLANT	NPT	NPT	$0	$0	$0	$0	$0
	DISTRIBUTION PLANT							
7	PRIMARY DEMAND RELATED	D4A		$3,639,106	$2,392,426	$219,151	$955,569	$62,614
8	SECONDARY DEMAND RELATED	D3A		$1,433,066	$942,127	$86,301	$376,300	$24,658
9	CUSTOMER RELATED	C4A		$3,262,004	$1,795,289	$760,079	$532,451	$990

10	SUB-TOTAL DISTR PLANT		SPD	$8,334,177	$5,129,843	$1,065,531	$1,864,320	$88,262
11	LIGHTING SPECIFIC	LDE		$0	$0	$0	$0	$0

12	TOTAL DISTRIBUTION PLANT	NPD	NPD	$8,334,177	$5,129,843	$1,065,531	$1,864,320	$88,262
	GENERAL AND INTANGIBLE PLANT							
13	PRODUCTION RELATED	NPP		$0	$0	$0	$0	$0
14	TRANSMISSION RELATED	NPT		$0	$0	$0	$0	$0
15	DISTRIBUTION RELATED	NPD		$118,149	$72,722	$15,106	$26,429	$1,252
	CUST ACCT/SERV & INFO/							
16	SALES RELATED	C2A		$33,665	$18,529	$7,844	$5,495	$10

17	TOTAL GENERAL & INTANGIBLE PLANT	NPG	NPG	$151,814	$91,251	$22,950	$31,924	$1,262

18	TOTAL NET PLANT IN SERVICE	NPR	NPR	$8,485,991	$5,221,094	$1,088,481	$1,896,244	$89,524
				==================================				

Other Rate Base

LINE NO.	DESCRIPTION	CONTROL ALLOUT	TOTAL COMPANY	****** RATE BASE ***** RESIDENTIAL	SEASONAL	GENERAL SERVICE	LARGE POWER

1	NET PLANT IN SERVICE	NPRNPR	$8,485,991	$5,221,094	$1,088,481	$1,896,244	$89,524
	CONSTRUCTION WORK IN PROGRESS						
2	PRODUCTION PLANT	NPP	$0	$0	$0	$0	$0
3	TRANSMISSION PLANT	NPT	$0	$0	$0	$0	$0
4	DISTRIBUTION PLANT	NPD	$571,534	$351,789	$73,071	$127,850	$6,053
5	GENERAL PLANT	NPG	$0	$0	$0	$0	$0

6	TOAL CWIP	CWPCWP	$571,534	$351,789	$73,071	$127,850	$6,053
7	NET ACQUISITION ADJUSTMENT	D2AACQ	$0	$0	$0	$0	$0
8	PLANT HELD FOR FUTURE USE	E1APLH	$0	$0	$0	$0	$0
	MISC DEFERRED DEBITS						
9	PROD RELATED	NPP	$0	$0	$0	$0	$0
10	TRAN RELATED	NPT	$0	$0	$0	$0	$0
11	DIST RELATED	NPD	$245,218	$150,937	$31,351	$54,854	$2,597
12	GENR RELATED	NPG	$0	$0	$0	$0	$0
13	LABOR RELATED	LBR	$0	$0	$0	$0	$0
14	NPR RELATED	NPR	$0	$0	$0	$0	$0

15	TOTAL MISC DEFRD DEBITS		$245,218	$150,937	$31,351	$54,854	$2,597
	WORKING CAPITAL						
16	CASH WORK CAP,FUNDS,MAT&SUP	NPRMAS	$160,860	$98,971	$20,633	$35,945	$1,697
17	FUEL STOCK	E1AFUL	$0	$0	$0	$0	$0
18	PREPAID LIGNITE ROYALTIES	E1A	$0	$0	$0	$0	$0
19	OTHER PREPAYMENTS	NPR	$0	$0	$0	$0	$0

20	TOTAL WORKING CAPITAL		$160,860	$98,971	$20,633	$35,945	$1,697
21	UNAMORTIZED LOSS ON REACQD LTD	NPR	$0	$0	$0	$0	$0
22	DEFERRED FUEL	E1ADEF	$0	$0	$0	$0	$0
	(RATE BASE CONTINUED ON NEXT PAGE)						

Other Rate Base Continued

				****** RATE BASE******
				** C O N T I N U E D **
LINE		CONTROL	TOTAL	GENERALLARGE
NO.	DESCRIPTION	ALLOUT	COMPANY	RESIDENTIALSEASONALSERVICEPOWER
			--	
	ACCUMULATED DEFERRED INCOME TAX			
23	ACCT 281: POL CON	NPP	$0	$0$0$0$0
24	ACCT 282: LIBERAL DEP - PROD	NPP	$0	$0$0$0$0
25	TRAN	NPT	$0	$0$0$0$0
26	DIST	NPD	$0	$0$0$0$0
27	GENR	NPG	$0	$0$0$0$0
28	LIGNITE EXPLORATN	E1A	$0	$0$0$0$0
29	LABOR RELATED	LBR	$0	$0$0$0$0

30	TOTAL ACCOUNT 282		$0$0$0$0$0	
31	ACCT 283: THIS LINE RESERVED		$0	$0$0$0$0
32	LONG TERM DEBT LOSS	NPR	$0	$0$0$0$0

33	TOTAL ACCOUNT 283		$0$0$0$0$0	
34	ACCOUNT 190: PRODUCTION RELATED	NPP	$0	$0$0$0$0
35	PLANT RELATED	NPR	$0	$0$0$0$0
36	ENERGY RELATED	E1A	$0	$0$0$0$0
37	LABOR RELATED	LBR	$0	$0$0$0$0
38	FERC REFUND	TRN	$0	$0$0$0$0

39	TOTAL ACCOUNT 190		$0$0$0$0$0	
40	TOTAL ACCUM DEFRD INC TAX	ACCACC	$0$0$0$0$0	
41	INVESTMENT TAX CREDIT PRE '71	NPRPIC	$0	$0$0$0$0
42	CUSTOMER ADVANCES AND DEPOSITS	C3ACAD	($30,543)	($16,810)($7,117)($4,985)($9)
43	STORM DAMAGE & INJ & DAM RESRVS	D2ASDR	$0	$0$0$0$0
44	PNSN & MIS OP RSRVS, OTR DEF CR	OMAPEN	$0	$0$0$0$0
45	TRANSMISSION RATE REFUND RESERVE	TRN	$0	$0$0$0$0

46	TOTAL RATE BASE	RBTRBT	$9,433,060$5,805,981$1,206,419$2,109,908$99,862	
			==================================	

Operating Expenses. Operating expenses reflect O&M expenses, depreciation, property and other taxes (non-income related).

O&M Expenses

				*******OPER AND MTN EXPENSES*******
LINE		CONTROL	TOTAL	GENERALLARGE
NO.	DESCRIPTION	ALLOUT	COMPANY	RESIDENTIALSEASONALSERVICEPOWER

	PRODUCTION O&M EXPENSE			
1	FUEL EXPENSE - ACCT 501	E1A	0	0000
	PURCHASED POWER - ACCT 555			
2	DEMAND	D1A	846,089	620,85340,325176,3148,113
3	ENERGY	E1A	2,466,785	1,846,959134,275441,16537,149
4	NET OFF SYSTEM REVENUE	E1A	0	0000
	OTHER PRODUCTION O&M ACCTS			
5	DEMAND	D1A	0	0000
6	ENERGY	E1A	0	0000

7	TOTAL OTHER PRODUCTION O&M	PROPRO	00000	

8	TOTAL PRODUCTION O&M EXPENSE	OMPOMP	3,312,8742,467,812174,600617,47945,262	
9	TOTAL TRANSMISSION O&M EXPENSE	NPTOMT	0	0000
	DISTRIBUTION O&M EXPENSE			
10	LIGHTING SPECIFIC	LDE	12,401	0000
11	ALL OTHER	SPD	838,070	515,848107,148187,4738,875

12	TOTAL DISTRIBUTION O&M EXPENSE	OMDOMD	850,471515,848107,148187,4738,875	
	TOTAL CUST ACCT/SERV & INFO/			
13	SALES EXPENSE	C2AOMC	247,247	136,07657,61140,35875
	ADMINISTRATIVE & GENERAL EXPENSE			
14	PROP INSURANCE/INJ & DAMG	NPR	10,008	6,1571,2842,236106
15	CUST ACCT/SERV&INFO/SALES REL	LBR	179,157	109,70123,83239,5441,807

16	TOTAL ADMIN & GENERAL EXPENSE	OMAOMA	189,165115,85825,11641,7801,913	

17	TOTAL OPER & MTN EXPENSES	OMXOMX	4,599,7573,235,594364,475887,09056,125	
			==================================	

Other Operating Expenses

LINE NO.	DESCRIPTION	CONTROL ALLOU	TOTAL COMPANY	***EXPENSES OTHER THAN INCOME TAXES*** RESIDENTIAL	SEASONAL	GENERAL SERVICE	LARGE POWER
1	TOTAL OPER & MTN EXPENSES	OMX	$4,599,757	$3,235,594	$364,475	$887,090	$56,125
	DEPRECIATION & AMORTIZATION EXPENSES						
2	PRODUCTION	NPP	$0	$0	$0	$0	$0
3	TRANSMISSION	NPT	$0	$0	$0	$0	$0
4	DISTRIBUTION	NPD	$489,872	$301,525	$62,631	$109,582	$5,188
5	GENERAL	NPG	$9,095	$5,466	$1,375	$1,913	$76
6	TOTAL DEPR & AMORT EXPEN	DEPDEP	$498,967	$306,991	$64,006	$111,495	$5,264
7	INTEREST ON CUSTOMER DEPOSITS	C3AICD	$0	$0	$0	$0	$0
	GENERAL TAXES						
8	AD VALOREM	NPRVAL	$72,336	$44,506	$9,278	$16,164	$763
9	CORP FRANCHISE TAX	NPRSFT	$0	$0	$0	$0	$0
10	MISCELLANEOUS GENERAL TAXES	LBRMIS	$16,711	$10,232	$2,223	$3,688	$169
11	REVENUE-RELATED (AS PROPOSED)	RTX	$0	$0	$0	$0	$0
12	TOTAL GENERAL TAXES	GTXGTX	$89,047	$54,738	$11,501	$19,852	$932
13	TOTAL EXPENSES EXCEPT INCOME TAX	EXPEXP	$5,187,771	$3,597,323	$439,982	$1,018,437	$62,321

<u>COSS Output.</u> The output of the COSS model is shown below.

Cost of Service Revenue Requirements

LINE NO.	DESCRIPTION	CONTROL	ALLOU	TOTAL COMPANY	RESIDENTIAL	SEASONAL	GENERAL SERVICE	LARGE POWER
					*****COST OF SERVICE***** ** (PROPOSED) **			
1	RATE BASE	RBT		$9,433,060	$5,805,981	$1,206,419	$2,109,908	$99,862
2	RETURN AT 4.11%	RET		$388,046	$238,840	$49,628	$86,795	$4,108
3	OPERATION & MAINTENANCE EXPENSES	OMX		$4,599,757	$3,235,594	$364,475	$887,090	$56,125
4	DEPRECIATION & AMORT EXPENSES	DEP		$498,967	$306,991	$64,006	$111,495	$5,264
5	INTEREST ON CUSTOMER DEPOSITS	ICD		$0	$0	$0	$0	$0
6	GENERAL TAXES	GTX		$89,047	$54,738	$11,501	$19,852	$932
7	FEDERAL AND STATE INCOME TAX	FST		$0	$0	$0	$0	$0
8	PROVISION FOR DEFERRED TAXES	PDT		$0	$0	$0	$0	$0
9	INVESTMENT TAX CREDIT - NET	ITN		$0	$0	$0	$0	$0
10	A F U D C	AFD		$0	$0	$0	$0	$0
11	COST OF SERVICE REVENUE REQUIREMENT BEFORE ATTRITION ADJUSTMENT	CSR	CSR	$5,575,817	$3,836,163	$489,610	$1,105,232	$66,429
12	LESS: FUEL REVENUE	FUL		$-0	$0	$-0	$-0	$-0
13	BASE COST OF SERVICE REVENUE REQUIREMENT	BRR	BRR	$5,575,817	$3,836,163	$489,610	$1,105,232	$66,429
14	ATTRITION ADJUSTMENT	BRR		$0	$0	$0	$0	$0
15	BASE COST OF SERVICE REVENUE REQUIREMENT AFTER ATTRITION ADJUSTMENT	ARR	ARR	$5,575,817	$3,836,163	$489,610	$1,105,232	$66,429
16	PLUS: FUEL REVENUE	FUL		$0	$0	$0	$0	$0
17	COST OF SERVICE REVENUE REQUIREMENT AFTER ATTRITION ADJUSTMENT			$5,575,817	$3,836,163	$489,610	$1,105,232	$66,429
18	LESS: MISCELLANEOUS REVENUE	MUCH IS DISTF		($47,255)	($29,086)	($6,042)	($10,571)	($500)
19	LESS: BULK TRANSMISSION REVENUE	D1A AI		$-0	$0	$-0	$-0	$-0
20	LESS: PRIMARY TRANSMISSION REVENUE		D2A ALLO	$-0	$0	$-0	$-0	$-0
21	LESS: NON-FRM SLS FOR RESALE			$-0	$0	$-0	$-0	$-0
22	NET ELECTRIC REVENUE REQUIREMENT			$5,528,562	$3,807,077	$483,568	$1,094,661	$65,929

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E-001 et al./PA-14-322	☐Nonpublic ☒Public
Requested From:	Randi Winter- Representing SMEC	Date of Request: 5/2/2018
Type of Inquiry:	Rate Design	Response Due: 5/14/2018

Requested by: John Kundert
Email Address(es): john.kundert@state.mn.us
Phone Number(s): 651-539-1740

Request Number: **66**
Topic: Extent of Revenue Apportionment in SMEC Member Cooperative Proposed Rates
Reference(s): SMEC compliance filing dated March 19, 2018

Request:

Please confirm that the unit costs developed in the different cooperatives' Class Cost of Service (CCOSS) Models are the basis for the proposed rates used identified in the filing.

a) If unit costs are not the basis for the proposed rates discussed in the filing, please list the customer classes by cooperative that vary from cost for former IPL customers.

Provide a discussion as to why those cooperatives identified in sub-part (a) of this question have elected to vary rates from the unit costs identified in the CCOSS for former IPL customers.

Response:

Yes, the unit costs developed in the different cooperatives' CCOSS Models are the primary basis for the proposed rates identified in SMEC's compliance filing. It is important to clarify, however, that while unit costs reflected in the CCOSS results are the primary consideration used in the development of proposed rates, unit costs can never be the sole consideration used in ratemaking. This is because the cooperatives must balance a variety of objectives and factors when developing rates. Relevant objectives and factors include, among other considerations, the Commission-approved Rate Plan, revenue needs, bill impacts, member communications, gradualism, rate consolidation and integration goals, and of course, the CCOSS results and unit costs identified therein. For this reason, the rate design for all customer classes is not exclusively tied to the unit costs reflected in the CCOSS for all cooperatives. Rather, each cooperative's board balanced all of the foregoing objectives and factors, including the CCOSS results, when making their final ratemaking decisions for the proposed rates.

To be completed by responder

Response Date: May 14, 2018
Response by: SMEC Cooperatives and Randi Winter, Felhaber Larson
Email Address: rwinter@felhaber.com
Phone Number: (612) 373-8546

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E-001 et al./PA-14-322	☐Nonpublic ☒Public	
Requested From:	Randi Winter- Representing SMEC	Date of Request:	5/2/2018
Type of Inquiry:	Rate Design	Response Due:	5/14/2018

Requested by: John Kundert
Email Address(es): john.kundert@state.mn.us
Phone Number(s): 651-539-1740

Request Number: 67
Topic: Effect of Proposed Rates on Average Bill by Cooperative by Class
Reference(s): SMEC compliance filing dated March 19, 2018

Request:

i. Please provide an analysis of the average monthly bill under current and proposed base rates for each customer class by cooperative for the Acquired area.

Response:

Please see Attachment 1, which provides an analysis of the average monthly bill under current and proposed base rates for each customer class by cooperative for the Acquired Areas.

ii. Please also provide an estimate of the effect of the removal of the 2 mill per kilowatt hour credit on the Power Cost Adjustment for on the average monthly bill for each customer class by cooperative for the Acquired Area.

Response:

The two (2) mill per kilowatt hour credit will have no effect on the power cost adjustment for any cooperative because this credit was not related to wholesale power costs. The 2-mill credit is indicated on a separate line on each member's monthly bill. Removal of the 2-mill credit at the expiration of the Initial Period (as provided in the Rate Plan) will affect every member of each cooperative in the same manner. Specifically, it will increase each member's bill by $0.20 for each 100 kilowatt hours purchased.

To be completed by responder

Response Date: May 14, 2018
Response by: SMEC Cooperatives and Randi Winter, Felhaber Larson
Email Address: rwinter@felhaber.com
Phone Number: (612) 373-8546

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E-001 et al./PA-14-322	☐Nonpublic ☒Public
Requested From:	Randi Winter- Representing SMEC	Date of Request: 5/2/2018
Type of Inquiry:	Rate Design	Response Due: 5/14/2018

Requested by: John Kundert
Email Address(es): john.kundert@state.mn.us
Phone Number(s): 651-539-1740

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iii. Please identify and quantify the effect of any additional riders other than the PCA on the average monthly bill under current and proposed rates by customer class by cooperative for the Acquired Area.

Response:

Aside from the 2-mill credit reflected in the current Initial Period rates, which will be removed as set forth in the Rate Plan at the expiration of the Initial Period when the new rates go into effect, there are no other riders on the month bills of any of the cooperatives' Acquired Area members under either the current or proposed rates.

To be completed by responder

Response Date: May 14, 2018
Response by: SMEC Cooperatives and Randi Winter, Felhaber Larson
Email Address: rwinter@felhaber.com
Phone Number: (612) 373-8546

Analysis of Average Monthly Bill for Each Customer Class under Current and Proposed Based Rates in the Acquired Areas

BENCO

	Average Monthly Bill				
Customer Class	Current Rates	Proposed Rates	Increase in Monthly Bill	Percent Increase	Removal of 2 mill Credit
Residential	$ 87.36	$ 91.72	$ 4.37	5%	$ 1.03
Small Commercial	$ 132.42	$ 139.04	$ 6.62	5%	$ 2.51
Large Power	$ 4,731.37	$ 4,967.94	$ 236.57	5%	$ 70.55
Corn Plus-Ethanol	$ 218,358.96	$ 229,276.91	$ 10,917.95	5%	$ 9,600.00

Brown

	Average Monthly Bill				
Customer Class	Current Rates	Proposed Rates	Increase in Monthly Bill	Percent Increase	Removal of 2 mill Credit
Residential	$ 97.59	$ 101.30	$ 3.71	3.8%	$ 1.75
Small Commercial	$ 195.11	$ 202.53	$ 7.41	3.8%	$ 3.78
Large Power	$ 5,480.60	$ 5,688.86	$ 208.26	3.8%	$ 91.43
Lighting	$ 302.06	$ 313.54	$ 11.48	3.8%	$ 4.37
Municipal Pumping	$ 144.86	$ 150.36	$ 5.50	3.8%	$ 2.64

Federated

	Average Monthly Bill				
Customer Class	Current Rates	Proposed Rates	Increase in Monthly Bill	Percent Increase	Removal of 2 mill Credit
Residential	$ 85.50	$ 89.77	$ 4.27	5%	$ 1.53
Small Commercial	$ 191.13	$ 199.36	$ 8.24	4%	$ 3.95
Large Power	$ 17,589.58	$ 18,494.26	$ 904.68	5%	$ 534.99
Lighting	$ 7.64	$ 7.64	$ -	0%	N/A
Municipal Pumping	$ 244.46	$ 262.38	$ 17.92	7%	$ 5.93

Overall revenue for Federated to increase by 5%.

Attachment 1 to the SMEC Response to DOC Information Request 67
MPUC Docket No. E-001 et al./PA-14-322

Freeborn Mower

Customer Class	Average Monthly Bill: Current Rates	Average Monthly Bill: Proposed Rates	Increase in Monthly Bill	Percent Increase	Removal of 2 mill Credit
Residential	$ 73.88	$ 77.80	$ 3.92	5%	$ 1.32
Small Commercial	$ 190.26	$ 200.45	$ 10.19	5%	$ 3.79
Large Power	$ 7,619.98	$ 7,988.66	$ 368.68	5%	$ 191.47
Lighting	$ 7.72	$ 8.12	$ 0.40	5%	$ 0.11
Municipal Pumping	$ 931.55	$ 979.07	$ 47.52	5%	$ 24.71

MiEnergy (formerly Tri-County)

Customer Class	Average Monthly Bill: Current Rates	Average Monthly Bill: Proposed Rates	Increase in Monthly Bill	Percent Increase	Removal of 2 mill Credit
Residential	$ 101.86	$ 106.44	$ 4.58	4%	$ 1.56
C&I <= 1000 kVA	$ 323.23	$ 339.36	$ 16.13	5%	$ 4.46
C&I > 1000 kVA	$ 15,178.53	$ 15,665.96	$ 487.43	3%	$ 202.76
Street Lighting	$ 7.50	$ 7.50	$ -	0%	N/A
Public Authority	$ 499.38	$ 528.07	$ 28.69	6%	$ 3.79

Overall revenue for MiEnergy to increase by 5%.

Minnesota Valley

Customer Class	Average Monthly Bill: Current Rates	Average Monthly Bill: Proposed Rates	Increase in Monthly Bill	Percent Increase	Removal of 2 mill Credit
Residential	$ 74.86	$ 78.59	$ 3.74	5%	$ 1.36
Small Commercial	$ 185.43	$ 194.65	$ 9.23	5%	$ 3.65
Large Power	$ 7,454.61	$ 7,823.54	$ 368.94	5%	$ 188.85
Lighting	$ 6.42	$ 6.74	$ 0.32	5%	$ 0.12
Municipal Pumping	$ 519.40	$ 543.99	$ 24.60	4.7%	$ 14.06

Nobles

Customer Class	Average Monthly Bill Current Rates	Average Monthly Bill Proposed Rates	Increase in Monthly Bill	Percent Increase	Removal of 2 mill Credit
Residential	$ 88.55	$ 92.95	$ 4.39	5%	$ 1.65
Small Commercial	$ 188.72	$ 198.51	$ 9.80	5%	$ 3.88
Large Power	$ 3,038.51	$ 3,173.46	$ 134.95	4%	$ 70.75
Street Lighting	$ 263.33	$ 263.33	$ -	0%	$ 3.64
Municipal Pumping	$ 125.46	$ 134.25	$ 8.79	7%	$ 2.40

Overall revenue for Nobles to increase by 5%.

Peoples

Customer Class	Average Monthly Bill Current Rates	Average Monthly Bill Proposed Rates	Increase in Monthly Bill	Percent Increase	Removal of 2 mill Credit
Residential	$ 77.01	$ 77.83	$ 0.82	1.06%	$ 1.34
Small Commercial	$ 193.60	$ 195.66	$ 2.05	1.06%	$ 5.60
Large Power	$ 7,059.37	$ 7,134.20	$ 74.83	1.06%	$ 134.25
Municipal Pumping	$ 1,007.45	$ 1,018.13	$ 10.68	1.06%	$ 10.91

Redwood

Customer Class	Average Monthly Bill Current Rates	Average Monthly Bill Proposed Rates	Increase in Monthly Bill	Percent Increase	Removal of 2 mill Credit
Residential	$ 85.91	$ 90.21	$ 4.30	5%	$ 1.54
Small Commercial	$ 248.55	$ 260.97	$ 12.42	5%	$ 4.29
Large Power	$ 3,150.23	$ 3,307.74	$ 157.51	5%	$ 120.34
Lighting	$ 320.87	$ 320.87	$ -	0%	$ 3.64
Municipal Pumping	$ 156.12	$ 163.93	$ 7.81	5%	$ 4.74

Overall revenue for Redwood to increase by 5%.

Sioux Valley

Customer Class	Average Monthly Bill: Current Rates	Average Monthly Bill: Proposed Rates	Increase in Monthly Bill	Percent Increase	Removal of 2 mill Credit
Residential	$ 99.92	$ 99.92	$ -	0%	$ 2.04
Residential (Farm and Rural)	$ 273.41	$ 273.41	$ -	0%	$ 5.68
Small Commercial	$ 178.69	$ 178.69	$ -	0%	$ 3.48
Large Power	$ 3,362.25	$ 3,362.25	$ -	0%	$ 79.66
Public Street & Highway Lighting	$ 263.54	$ 263.54	$ -	0%	$ 3.50
Other Sales to Public Authorities	$ 71.76	$ 71.76	$ -	0%	$ 1.14

South Central

Customer Class	Average Monthly Bill: Current Rates	Average Monthly Bill: Proposed Rates	Increase in Monthly Bill	Percent Increase	Removal of 2 mill Credit
Residential	$ 88.26	$ 92.68	$ 4.42	5%	$ 1.59
Small Commercial	$ 171.62	$ 180.14	$ 8.53	5%	$ 3.30
Large Power	$4,060.34	$4,263.54	$ 203.20	5%	$ 63.68
Lighting	$ 336.89	$ 336.89	$ -	0%	N/A
Municipal Pumping	$ 191.08	$ 201.39	$ 10.31	5%	$ 4.01

Steele-Waseca

Customer Class	Average Monthly Bill: Current Rates	Average Monthly Bill: Proposed Rates	Increase in Monthly Bill	Percent Increase	Removal of 2 mill Credit
Residential	$ 73.88	$ 77.80	$ 3.92	5%	$ 1.32
Small Commercial	$ 190.26	$ 200.45	$ 10.19	5%	$ 3.79
Large Power	$ 7,619.98	$ 7,988.66	$ 368.68	5%	$ 191.47
Lighting	$ 7.72	$ 8.12	$ 0.40	5%	$ 0.11
Municipal Pumping	$ 931.55	$ 979.07	$ 47.52	5%	$ 24.71

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E-001 et al./PA-14-322	☐Nonpublic ☒Public
Requested From:	Randi Winter- Representing SMEC	Date of Request: 5/2/2018
Type of Inquiry:	Rate Design	Response Due: 5/14/2018

Requested by: John Kundert
Email Address(es): john.kundert@state.mn.us
Phone Number(s): 651-539-1740

Request Number: **67**
Topic: Effect of Proposed Rates on Average Bill by Cooperative by Class
Reference(s): SMEC compliance filing dated March 19, 2018

Request:

i. Please provide an analysis of the average monthly bill under current and proposed base rates for each customer class by cooperative for the Acquired area.

Response:

Please see Attachment 1, which provides an analysis of the average monthly bill under current and proposed base rates for each customer class by cooperative for the Acquired Areas.

Updated Response on 5/22/18:

Please see Amended Attachment 1, which provides an analysis of the average monthly bill under current and proposed base rates for each customer class by cooperative for the Acquired Areas. The amended attachment has removed the power cost adjustments for Brown and Peoples.

To be completed by responder

Response Date: May 14, 2018; Attachment 1 Amended on 5/22/18
Response by: SMEC Cooperatives and Randi Winter, Felhaber Larson
Email Address: rwinter@felhaber.com
Phone Number: (612) 373-8546

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E-001 et al./PA-14-322	☐Nonpublic ☒Public
Requested From:	Randi Winter- Representing SMEC	Date of Request: 5/2/2018
Type of Inquiry:	Rate Design	Response Due: 5/14/2018

Requested by:	John Kundert
Email Address(es):	john.kundert@state.mn.us
Phone Number(s):	651-539-1740

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ii. Please also provide an estimate of the effect of the removal of the 2 mill per kilowatt hour credit on the Power Cost Adjustment for on the average monthly bill for each customer class by cooperative for the Acquired Area.

Response:

The two (2) mill per kilowatt hour credit will have no effect on the power cost adjustment for any cooperative because this credit was not related to wholesale power costs. The 2-mill credit is indicated on a separate line on each member's monthly bill. Removal of the 2-mill credit at the expiration of the Initial Period (as provided in the Rate Plan) will affect every member of each cooperative in the same manner. Specifically, it will increase each member's bill by $0.20 for each 100 kilowatt hours purchased.

iii. Please identify and quantify the effect of any additional riders other than the PCA on the average monthly bill under current and proposed rates by customer class by cooperative for the Acquired Area.

Response:

Aside from the 2-mill credit reflected in the current Initial Period rates, which will be removed as set forth in the Rate Plan at the expiration of the Initial Period when the new rates go into effect, there are no other riders on the month bills of any of the cooperatives' Acquired Area members under either the current or proposed rates.

To be completed by responder

Response Date:	May 14, 2018; Attachment 1 Amended on 5/22/18
Response by:	SMEC Cooperatives and Randi Winter, Felhaber Larson
Email Address:	rwinter@felhaber.com
Phone Number:	(612) 373-8546

Analysis of Average Monthly Bill for Each Customer Class under Current and Proposed Based Rates in the Acquired Areas

BENCO

Customer Class	Average Monthly Bill: Current Rates	Average Monthly Bill: Proposed Rates	Increase in Monthly Bill	Percent Increase	Removal of 2 mill Credit
Residential	$ 87.36	$ 91.72	$ 4.37	5%	$ 1.03
Small Commercial	$ 132.42	$ 139.04	$ 6.62	5%	$ 2.51
Large Power	$ 4,731.37	$ 4,967.94	$ 236.57	5%	$ 70.55
Corn Plus-Ethanol	$ 218,358.96	$ 229,276.91	$ 10,917.95	5%	$ 9,600.00

Brown (Amended 5/22/18 to remove power cost adjustment)

Customer Class	Average Monthly Bill: Current Rates	Average Monthly Bill: Proposed Rates	Increase in Monthly Bill	Percent Increase	Removal of 2 mill Credit
Residential	$ 90.84	$ 94.30	$ 3.45	3.8%	$ 1.75
Small Commercial	$ 179.63	$ 186.45	$ 6.83	3.8%	$ 3.78
Large Power	$ 5,077.27	$ 5,270.21	$ 192.94	3.8%	$ 91.43
Lighting	$ 285.68	$ 296.54	$ 10.86	3.8%	$ 4.37
Municipal Pumping	$ 135.45	$ 140.60	$ 5.15	3.8%	$ 2.64

Federated

Customer Class	Average Monthly Bill: Current Rates	Average Monthly Bill: Proposed Rates	Increase in Monthly Bill	Percent Increase	Removal of 2 mill Credit
Residential	$ 85.50	$ 89.77	$ 4.27	5%	$ 1.53
Small Commercial	$ 191.13	$ 199.36	$ 8.24	4%	$ 3.95
Large Power	$ 17,589.58	$ 18,494.26	$ 904.68	5%	$ 534.99
Lighting	$ 7.64	$ 7.64	$ -	0%	N/A
Municipal Pumping	$ 244.46	$ 262.38	$ 17.92	7%	$ 5.93

Overall revenue for Federated to increase by 5%.

Freeborn Mower

Customer Class	Average Monthly Bill Current Rates	Average Monthly Bill Proposed Rates	Increase in Monthly Bill	Percent Increase	Removal of 2 mill Credit
Residential	$ 73.88	$ 77.80	$ 3.92	5%	$ 1.32
Small Commercial	$ 190.26	$ 200.45	$ 10.19	5%	$ 3.79
Large Power	$ 7,619.98	$ 7,988.66	$ 368.68	5%	$ 191.47
Lighting	$ 7.72	$ 8.12	$ 0.40	5%	$ 0.11
Municipal Pumping	$ 931.55	$ 979.07	$ 47.52	5%	$ 24.71

MiEnergy (formerly Tri-County)

Customer Class	Average Monthly Bill Current Rates	Average Monthly Bill Proposed Rates	Increase in Monthly Bill	Percent Increase	Removal of 2 mill Credit
Residential	$ 101.86	$ 106.44	$ 4.58	4%	$ 1.56
C&I <= 1000 kVA	$ 323.23	$ 339.36	$ 16.13	5%	$ 4.46
C&I > 1000 kVA	$ 15,178.53	$ 15,665.96	$ 487.43	3%	$ 202.76
Street Lighting	$ 7.50	$ 7.50	$ -	0%	N/A
Public Authority	$ 499.38	$ 528.07	$ 28.69	6%	$ 3.79

Overall revenue for MiEnergy to increase by 5%.

Minnesota Valley

Customer Class	Average Monthly Bill Current Rates	Average Monthly Bill Proposed Rates	Increase in Monthly Bill	Percent Increase	Removal of 2 mill Credit
Residential	$ 74.86	$ 78.59	$ 3.74	5%	$ 1.36
Small Commercial	$ 185.43	$ 194.65	$ 9.23	5%	$ 3.65
Large Power	$ 7,454.61	$ 7,823.54	$ 368.94	5%	$ 188.85
Lighting	$ 6.42	$ 6.74	$ 0.32	5%	$ 0.12
Municipal Pumping	$ 519.40	$ 543.99	$ 24.60	4.7%	$ 14.06

Nobles

Customer Class	Average Monthly Bill: Current Rates	Average Monthly Bill: Proposed Rates	Increase in Monthly Bill	Percent Increase	Removal of 2 mill Credit
Residential	$ 88.55	$ 92.95	$ 4.39	5%	$ 1.65
Small Commercial	$ 188.72	$ 198.51	$ 9.80	5%	$ 3.88
Large Power	$3,038.51	$3,173.46	$ 134.95	4%	$ 70.75
Street Lighting	$ 263.33	$ 263.33	$ -	0%	$ 3.64
Municipal Pumping	$ 125.46	$ 134.25	$ 8.79	7%	$ 2.40

Overall revenue for Nobles to increase by 5%.

Peoples (Amended 5/22/18 to remove power cost adjustment)

Customer Class	Average Monthly Bill: Current Rates	Average Monthly Bill: Proposed Rates	Increase in Monthly Bill	Percent Increase	Removal of 2 mill Credit
Residential	$ 76.93	$ 77.75	$ 0.82	1.06%	$ 1.34
Small Commercial	$ 192.75	$ 194.79	$ 2.04	1.06%	$ 5.60
Large Power	$ 7,059.37	$ 7,134.20	$ 74.83	1.06%	$ 34.25
Municipal Pumping	$ 1,007.45	$ 1,018.13	$ 10.68	1.06%	$ 10.91

Redwood

Customer Class	Average Monthly Bill: Current Rates	Average Monthly Bill: Proposed Rates	Increase in Monthly Bill	Percent Increase	Removal of 2 mill Credit
Residential	$ 85.91	$ 90.21	$ 4.30	5%	$ 1.54
Small Commercial	$ 248.55	$ 260.97	$ 12.42	5%	$ 4.29
Large Power	$3,150.23	$3,307.74	$ 157.51	5%	$ 120.34
Lighting	$ 320.87	$ 320.87	$ -	0%	$ 3.64
Municipal Pumping	$ 156.12	$ 163.93	$ 7.81	5%	$ 4.74

Overall revenue for Redwood to increase by 5%.

Amended Attachment 1 to the SMEC Response to DOC Information Request 67
MPUC Docket No. E-001 et al./PA-14-322

Sioux Valley

Customer Class	Average Monthly Bill: Current Rates	Average Monthly Bill: Proposed Rates	Increase in Monthly Bill	Percent Increase	Removal of 2 mill Credit
Residential	$ 99.92	$ 99.92	$ -	0%	$ 2.04
Residential (Farm and Rural)	$ 273.41	$ 273.41	$ -	0%	$ 5.68
Small Commercial	$ 178.69	$ 178.69	$ -	0%	$ 3.48
Large Power	$ 3,362.25	$ 3,362.25	$ -	0%	$ 79.66
Public Street & Highway Lighting	$ 263.54	$ 263.54	$ -	0%	$ 3.50
Other Sales to Public Authorities	$ 71.76	$ 71.76	$ -	0%	$ 1.14

South Central

Customer Class	Average Monthly Bill: Current Rates	Average Monthly Bill: Proposed Rates	Increase in Monthly Bill	Percent Increase	Removal of 2 mill Credit
Residential	$ 88.26	$ 92.68	$ 4.42	5%	$ 1.59
Small Commercial	$ 171.62	$ 180.14	$ 8.53	5%	$ 3.30
Large Power	$4,060.34	$4,263.54	$ 203.20	5%	$ 63.68
Lighting	$ 336.89	$ 336.89	$ -	0%	N/A
Municipal Pumping	$ 191.08	$ 201.39	$ 10.31	5%	$ 4.01

Steele-Waseca

Customer Class	Average Monthly Bill: Current Rates	Average Monthly Bill: Proposed Rates	Increase in Monthly Bill	Percent Increase	Removal of 2 mill Credit
Residential	$ 73.88	$ 77.80	$ 3.92	5%	$ 1.32
Small Commercial	$ 190.26	$ 200.45	$ 10.19	5%	$ 3.79
Large Power	$ 7,619.98	$ 7,988.66	$ 368.68	5%	$ 191.47
Lighting	$ 7.72	$ 8.12	$ 0.40	5%	$ 0.11
Municipal Pumping	$ 931.55	$ 979.07	$ 47.52	5%	$ 24.71

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E-001 et al./PA-14-322	☐Nonpublic ☒Public	
Requested From:	Randi Winter- Representing SMEC	Date of Request:	5/2/2018
Type of Inquiry:	Rate Design	Response Due:	5/14/2018

Requested by: John Kundert
Email Address(es): john.kundert@state.mn.us
Phone Number(s): 651-539-1740

Request Number: **68**
Topic: Merging rate classes
Reference(s): SMEC compliance filing dated January 10, 2018

Request:

Please identify which SMEC cooperatives have low-income assistance programs.

Are customers in the Acquired Areas eligible for those low-income programs?

Could the member cooperatives' low-income programs help mitigate rate increases resulting from the merger of former IPL rate schedules with the specific SMEC cooperative's existing rate schedules for former IPL customers?

Response:

All of the SMEC member cooperatives administer, participate in, and/or contribute to low-income assistance programs. These programs are available to qualifying Acquired Area members who meet the various low-income assistance programs' criteria in the same manner that they are available to qualifying Legacy Area members that meet such criteria.

Yes, the SMEC member cooperatives believe that their low-income assistance programs can help mitigate rate increases that may result from the merger of the former IPL rate schedules with the specific SMEC cooperatives' existing rate schedules after the completion of the Transition Period. Such mitigation will be predominantly through assistance that low income programs provide qualifying members with respect to paying their utility bills. The cooperatives have found that such assistance has the added benefit of reducing the overall number of uncollectible accounts, which in turn reduces costs for all members.

To be completed by responder

Response Date: May 14, 2018
Response by: SMEC Cooperatives and Randi Winter, Felhaber Larson
Email Address: rwinter@felhaber.com
Phone Number: (612) 373-8546

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E-001 et al./PA-14-322	☐Nonpublic ☒Public
Requested From:	Randi Winter- Representing SMEC	Date of Request: 5/2/2018
Type of Inquiry:	Rate Design	Response Due: 5/14/2018

Requested by:	John Kundert
Email Address(es):	john.kundert@state.mn.us
Phone Number(s):	651-539-1740

It is also likely that energy efficiency measures funded by individual cooperatives will mitigate Acquired Area members' energy bills. Such measures include assistance with weatherization, lighting, and high-efficiency appliance upgrades intended to improve members' daily living while reducing out-of-pocket expenses that would otherwise be spent on increased energy usage. Any mitigation of household energy costs will be dependent on the specific project and the individual member's home energy consumption patterns.

Examples of the low-income programs available to Acquired Area members include but are not limited to the following:

- **<u>Community Action Partnerships (CAPs)</u>: SMEC cooperatives provide funding to various CAPs, which work with low income members of the cooperatives and surrounding communities with respect to bill assistance and funding for energy saving projects. CAPs to which SMEC cooperatives contribute include:**
  - **United Community Action Partnership**
  - **Minnesota Action Council (Mankato)**
  - **Minnesota Valley Action Council**
  - **Southeastern Minnesota Citizen's Action Council**
  - **Southwestern Minnesota Opportunity Council**

- **<u>Other Low-Income Programs</u>: SMEC cooperatives provide funding to the following additional low-income programs located in communities where SMEC cooperatives provide electric service:**
  - **City of Okabena**
  - **Fuel Assistance Agencies**
  - **Habitat for Humanity**

To be completed by responder

Response Date:	May 14, 2018
Response by:	SMEC Cooperatives and Randi Winter, Felhaber Larson
Email Address:	rwinter@felhaber.com
Phone Number:	(612) 373-8546

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E-001 et al./PA-14-322	☐Nonpublic ☒Public	
Requested From:	Randi Winter- Representing SMEC	Date of Request:	5/2/2018
Type of Inquiry:	Rate Design	Response Due:	5/14/2018

Requested by: John Kundert
Email Address(es): john.kundert@state.mn.us
Phone Number(s): 651-539-1740

- **Heat Share**
- **Nobles Cooperative Electric's K12 Program**
- **RECare**
- **Round Lake Senior Center**
- **Round Up Programs**
- **Salvation Army**

To be completed by responder

Response Date: May 14, 2018
Response by: SMEC Cooperatives and Randi Winter, Felhaber Larson
Email Address: rwinter@felhaber.com
Phone Number: (612) 373-8546

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Comments

Docket No. E001, 115, 140, 105, 139, 124, 126, 145, 132, 114, 6521, 142, 143/PA-14-322

Dated this 29th day of May 2018

/s/Sharon Ferguson

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Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_14-322_Official

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