414 Nicollet Mall
Minneapolis, Minnesota 55401-1993

June 8, 2015

PUBLIC DOCUMENTS
TRADE SECRET INFORMATION AND
NON-PUBLIC DATA EXCISED

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

—Via Electronic Filing—

RE: XCEL ENERGY ELECTRIC RATE CASE
REPLY COMMENTS
CCOSS AND REVENUE APPORTIONMENT SCHEDULES
DOCKET NO. E002/GR-13-868

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission the enclosed Reply Comments to the May 28, 2015 Comments of the Minnesota Department of Commerce – Division of Energy Resources regarding our May 1, 2015 Class Cost of Service Study (CCOSS) and revenue apportionment compliance filing.

Our Reply Comments and Attachments A, B, C, D, E and F include Trade Secret information protected by the Minnesota Data Practices Act. Xcel Energy maintains this information as Trade Secret based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. For this reason, we ask that the data be treated as Non-Public pursuant to Minn. Stat. § 13.37, subd. 1(b). We have identified the Trade Secret information pursuant to Minn. Rule 7829.0500.

We have electronically filed this document with the Commission, which also constitutes service on the Department of Commerce and the Office of the Attorney General – Antitrust and Utilities Division. A copy of this filing has been served on all parties on the official service list in this docket.

Please contact Amy Liberkowski at amy.a.liberkowski@xcelenergy.com or (612) 330-6613 if you have any questions regarding this Compliance Filing.

Sincerely,

/s/

GAIL A. BARANKO
MANAGER, REGULATORY PROJECT MANAGEMENT
NSPM REGULATORY

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
John Tuma	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY FOR AUTHORITY TO INCREASE RATES FOR ELECTRIC SERVICE IN THE STATE OF MINNESOTA

Docket No. E002/GR-13-868

REPLY COMMENTS

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission Reply Comments to the May 28, 2015 Comments of the Minnesota Department of Commerce – Division of Energy Resources regarding our May 1, 2015 Class Cost of Service Study (CCOSS) and revenue apportionment compliance filing. We also take this opportunity to respond to the Office of Attorney General's May 28, 2015 Comments on the calculation of the interim rate refund for in this docket.

REPLY TO THE DEPARTMENT'S CCOSS/REVENUE APPORTIONMENT COMMENTS

We appreciate the Department's thorough review of our compliance filing. As noted in the Department's May 28, 2015 Comments, we have worked with the Department since the Commission's deliberations on issues related to the CCOSS, meeting in person on May 21, 2015 and providing discovery responses to the Department on May 27, 2015 and May 28, 2015.

The Company believes its May 1, 2015 compliance filing generally reflected the decisions made by the Commission during its deliberations and is consistent with the Commission's May 8, 2015 Order. We did identify one error in our May 1, 2015 compliance filing related to the allocation of economic development discounts to classes. We discussed this error with the Department at the May 21, 2015 meeting and quantified the class impact in our May 27, 2015 discovery responses. Revised 2014 and 2015 CCOSSs, included as Attachment A and Attachment B to these Reply Comments, include the correct allocation of economic development discounts to classes.

After reviewing the Department's Comments, we now understand the Department supports updating the demand and energy classifications for all production plant, including Company-owned wind, that are used to develop the location method allocator for Other Production O&M. We agree that approach comports with all of the decisions in the Commission's May 8, 2015 Order. This change is reflected in the revised 2014 and 2015 CCOSSs included as Attachment A and Attachment B to these Reply Comments.

Overall, the economic development correction and updating the location method calculation result in minor changes to overall class cost and revenue responsibilities.

Table 1
Summary of Changes to 2015 Class Cost and Revenue Responsibilities
($1,000's)

	MN	Residential	Commercial Non-Demand	C&I Demand	Lighting
Cost Responsibilities					
Adj. Rev. Req. – May 1, 2015 Compliance CCOSS	$2,994,440	$1,087,369	$113,601	$1,767,681	$25,789
Impact of Economic Development Correction	*$0*	*$470*	*$50*	*($520)*	*$0*
Impact of Location Method Update	*$0*	*($698)*	*($48)*	*$694*	*$52*
Revised Rev. Req.	$2,994,440	$1,087,141	$113,603	$1,767,855	$25,841
Difference	*$0* *0.00%*	*($228)* *(0.02%)*	*$2* *0.00%*	*$174* *0.01%*	*$53* *0.20%*
Revenue Responsibilities					
Percent Revenue Increase – May 1, 2015 Compliance Filing	5.94%	6.19%	5.10%	5.93%	0.00%
Percent Revenue Increase – Revised CCOSS	5.94%	6.18%	5.10%	5.94%	0.00%
Difference	*0.00%*	*(0.01%)*	*0.00%*	*0.01%*	*0.00%*

We also acknowledge the Department's difficulty in assessing the May 1, 2015 compliance CCOSSs during the comment period. Those CCOSSs were developed using the Company's CCOSS model – the same model we have used to develop CCOSSs for the last five electric rate cases. The model includes nearly 9,000 rows of clearly itemized calculations. We also provided the Department and other parties with detailed instructions regarding the operation of the model, just as we have in prior cases. As part of our overall effort to make our initial filing more thorough, we significantly expanded Direct Testimony and associated schedules in this case and provided 25 pages of pre-filed discovery focused on CCOSS topics.[1]

The Company's CCOSS model is necessarily detailed in order to accurately calculate class cost responsibilities of a system as complicated as ours. But we also acknowledge the clarity of the model can be improved and we are willing to work with the Department to adopt changes to the model that can assist the Department in its oversight responsibilities. We are also willing to provide additional documentation and instruction on the CCOSS model, with the materials being developed through a cooperative process with the Department that focuses on its specific needs.

That being said, the Commission has relied on the Company's CCOSS model for the Company's last five rate cases and can continue to do so in this case.

1. Revenue Requirement Issues

The Department concluded the compliance CCOSSs correctly reflected the financial impacts of the Commission's May 8, 2015 Order, except for rate of return for 2015 Step, Corporation Aviation adjustment, Production Tax Credits for Borders Wind and Pleasant Valley and implementation of the Commission's Monticello Order.[2] The Company acknowledges we interpret the Commission's May 8, 2015 Order regarding rate of return for 2015 Step and the Commission's Monticello Order differently than does the Department.[3] This difference of opinion results in different underlying

[1] Ex. 102, Peppin Direct at 5.
[2] Department May 28, 2015 Comments at 7.
[3] The Company explained its position on the merits of the rate of return for the 2015 Step and the implementation of the Commission's Monticello order in its Petition for Reconsideration and in its Answer to Petitions for Reconsideration. *See* Xcel Energy Petition for Reconsideration at 1-6 and Xcel Energy Answer to Petitions for Reconsideration at 7-12. The Company also provided the Department with additional information regarding the revenue requirement impact of the Production Tax Credits in its Supplemental Responses to DOC-4 and DOC-5, both submitted on May 28, 2015 and revised June 8, 2015. Copies of those responses are included as Attachments C and D to these Reply Comments. Finally, the Office of Attorney General has not indicated that the

revenue requirements. But differences of opinion regarding revenue requirements issues is unrelated to whether the CCOSS correctly classifies and allocates the ultimate revenue requirement to customer classes. We will reflect any clarifications provided by the Commission on these issues in the final compliance CCOSS.

2. Economic Development Discounts

Economic development discounts impact two portions of the CCOSS: present revenues and the rate discounts allocated to classes.[4] The Company agreed with the Department's recommendation to set 2014 and 2015 economic development discounts at 2013-actual levels.[5] Agreeing to the lower level of economic development discounts resulted in a corresponding increase in present revenues, which also reduced the overall deficiency. Attachment E to this filing demonstrates the present revenues included in both the January 16, 2015 compliance filing and in the May 1, 2015 compliance filing reflect the agreed upon level of economic development discounts.

Company witness Mr. Michael Peppin explained in his Direct Testimony that the Company's CCOSS includes specific line items that allocate the costs of interruptible rate discounts and economic development discounts to classes.[6] The Company, however, inadvertently ***[TRADE SECRET BEGINS***

TRADE SECRET ENDS]
in its May 1, 2015 compliance CCOSSs. We discussed this error with the Department on May 21, 2015 and quantified its impact in our discovery responses issued on May 27, 2015.[7]

Company has incorrectly calculated the revenue requirement impact of the Commission's decisions regarding corporate aviation.

[4] Rate discounts includes the cost of economic development discounts and the cost of interruptible rate discounts. Ex. 102, Peppin Direct at 6-7. Mr. Peppin discussed the process of and reasoning for allocating rate discounts to classes in both Direct and Rebuttal Testimony. *See* Ex. 102, Peppin Direct at 6-7; Ex. 103, Peppin Rebuttal at 13-15.

[5] Ex. 107, Huso Rebuttal at 38-39.

[6] Ex. 102, Peppin Direct at 7-8.

[7] *See* Pages 8-9 of the Company's Supplemented Revised Responses to DOC-4 and DOC-5, included as Attachments C and D to these Reply Comments.

Table 2
Impact of Correct Allocation of
Economic Development Discounts – 2015 CCOSS

	MN	Residential	Commercial Non-Demand	C&I Demand	Lighting
Adj. Rev. Req. – May 1, 2015 Compliance CCOSS	$2,994,440	$1,087,369	$113,601	$1,767,681	$25,789
Adj. Rev. Req – Economic Development Allocation Correction	$2,994,440	$1,087,839	$113,651	$1,767,161	$25,789
Difference	*$0* *0.00%*	*$470* *0.04%*	*$50* *0.04%*	*($520)* *(0.03%)*	*$0* *0.00%*

We regret this error and have corrected it in Attachments A and B.

Attachment F to this filing includes a reconciliation of total rate discounts based on the decisions reflected in the Commission's May 8, 2015 Order and the total rate discounts used in the Company's Rebuttal Testimony. Attachment F shows: 1) that there has been no change in the level of economic development discounts from what was agreed to in Rebuttal Testimony; and 2) the change in total rate discounts from Rebuttal levels is entirely attributable to the level of interruptible rate discounts, which changed to reflect the Commission's decisions on the underlying sales. We therefore do not agree with the Department's recommendation to limit total rate discounts to $68.514 million.

3. Plant Stratification and Other Production O&M

As noted in the Department's Comments, the Company and the Department discussed Plant Stratification and the classification and allocation of Other Production O&M in our May 21, 2015 meeting. In that meeting, we explained that we did apply the Plant Stratification method in the May 1, 2015 compliance CCOSSs to all fixed production plant costs, including Nobles and Grand Meadow. We provided details regarding the Plant Stratification of all fixed production plant costs, including Nobles and Grand Meadow, in our May 27, 2015 discovery responses.[8]

When developing the May 1, 2015 compliance CCOSS, we interpreted the Commission's Order to require the use of the location method, as quantified in Table

[8] *See* Pages 7-8 of the Company's Supplement Revised Responses to DOC-4 and DOC-5, included as Attachments C and D to these Reply Comments.

7 of Mr. Peppin's Direct Testimony. We understood the Department to agree with that approach because it was the only version of the location method discussed or supported in the record of this case. Further, when the Department asked the Company to run the CCOSS model using the location method, its information requests referenced Table 7 of Mr. Peppin's Direct Testimony.[9] That table reflected the Company's proposal to classify Company-owned wind as 100% demand, even though the Department did not support that approach.[10] The 2014 and 2015 compliance CCOSSs submitted on May 1, 2015 carried this approach forward, essentially treating the development of the location method allocators and the classification of Nobles and Grand Meadow as being independent from one another.

After reviewing the Department's Comments, we now understand the Department supports updating the demand and energy classifications for all all production plant, including Company-owned wind, that are used to develop the location method allocator for Other Production O&M. We agree that approach comports with all of the decisions in the Commission's May 8, 2015 Order. Attachments G and H include the location method calculation for both the 2014 and 2015 CCOSSs based on updated demand and energy classifications for all production plant at the final ordered Other Production O&M levels.

Table 3
Impact of Updating All Production Plant Demand and Energy Classifications to Calculate the Location Method – 2015 CCOSS

	MN	Residential	Commercial Non-Demand	C&I Demand	Lighting
Adj. Rev. Req. – May 1, 2015 Compliance CCOSS	$2,994,440	$1,087,369	$113,601	$1,767,681	$25,789
Adj. Rev. Req – Location Method Update	$2,994,440	$1,086,671	$113,552	$1,768,376	$25,841
Difference	*$0* *0.00%*	*($698)* *(0.06%)*	*($48)* *(0.04%)*	*$694* 0.04%	*$52* *0.20%*

The Revised 2014 and 2015 CCOSSs included as Attachments A and B to reflect the updated classification of Other Production O&M costs.

[9] *See e.g.*, Ex. 408, Ouanes Direct at Schedules 18 and 19.
[10] *See* Ex. 408, Ouanes Direct at 22-28.

4. January 16, 2015 Sales and Revenue Filing

The Company's CCOSS includes interdepartmental revenues in the calculation of total revenue requirements,[11] but does not include interdepartmental sales or interdepartmental customers in the calculation of customer-based or energy-based allocators. Interdepartmental sales are non-retail. It would therefore be inappropriate to include those customers and those sales in the calculation of allocators used to allocate retail costs. We have used this approach in each of our last five rate cases without objection.

The Company's CCOSS and revenue calculations also appropriately handle Protective Lighting customers. The Company's CCOSS includes several customer-based allocators. The customers included in each allocator differ due to the nature of the revenues and costs being allocated. As explained in Attachment I, Protective Lighting customers are excluded from some of the customer-based allocators. Further, the Company's January 16, 2015 compliance filing focuses on the number of Protective Lightings installations for the development of test year sales and rate revenues, not the number of customers.[12] Similar to interdepartmental sales, the Company has used this approach for Protective Lighting in each of its last five rate cases without objection.

Attachment I reconciles each CCOSS customer-based allocator to the Company's January 16, 2015 compliance filing. Attachment I also reconciles the sales used in the CCOSSs to the January 16, 2015 compliance filing.

In the absence of any language in the Order or in the record addressing a change to the treatment of interdepartmental sales or Protective Lighting, we continued to apply our historical practice in the compliance CCOSSs. We request the Commission affirm our approach as being appropriate.

5. Revenue Apportionment.

Order Point 48(d) states that "[i]f the revised CCOSS shows the Residential class is currently contributing less than its share of cost, move the Residential class 75% closer to cost." The Commission's May 8, 2015 Order also provides that "In this case, the Commission believes that the *classes can reasonably be set at—or significantly closer*

---

[11] *See* Line 4 of Schedule A3, Page 7 of the Company's May 1, 2015 compliance filing.
[12] *See* Page 16 of Attachments G1 and G2 to the Company's January 16, 2015 compliance filing.

to—their CCOSS-indicated cost."[13] This language evidences a clear intention on the part of the Commission to set the percentage of revenue coming from the Residential class (and other classes) at a level that is closer to the cost-based percentages indicated in the final CCOSS. The alternative interpretation identified by the Department in its comments achieves the opposite result – moving the Residential class (and the C&I Demand class) *away* from cost.

We agree with the Department that some of the language from page 84 of the Commission's Order could be interpreted as requiring a different approach than what was reflected in the Company's May 1, 2015 compliance filing.[14] The Department's Table 2, however, shows that such an interpretation results in an allocation where the Residential class (and the C&I Demand class) moves *away* from cost.

Reproduction of Table 2 from Department's Comments

Table 2: Apportionment as a Percent of Total Income

Class	Revised Current	Revised CCOSS	Xcel Proposed Apportion	PUC Methodology
Residential	36.20%	36.31%	36.28%	35.78%
Non-Demand	3.82%	3.79%	3.79%	3.79%
C&I Demand	59.05%	59.03%	59.04%	59.55%
Lighting	0.93%	0.86%	0.88%	0.88%
Total	100.00%	100.00%	100.00%	100.00%

If the "PUC Methodology" reflected in the Department's Table 2 is adopted, the Residential class's share of total revenue will decrease from 36.20% to 35.78%. This decrease is not justified on a cost basis because the compliance CCOSS showed the Residential class's cost-based revenue responsibility to be 36.31% - higher than the share of Revenues currently collected from the Residential class.[15] The "PUC Methodology" included in Table 2 is fundamentally at odds with Order Point 48(d) and with the portions of Page 84 indicating a clear intent to move classes *closer* to cost. And the movement *away* from cost is not limited to the Residential class: the C&I Demand class would move further above cost by an even greater share than the Residential class would move below cost.

[13] May 8, 2015 Order at 84 (emphasis added).
[14] Department May 28, 2015 Comments at 13 (citing page 84 of the Commission's May 8, 2015 Order).
[15] In the revised 2015 CCOSS included in Attachment B, the Residential class's cost-based revenue responsibility is 36.31%.

In comparison, the Company's approach adjusts the Residential class apportionment by 75% of the difference between the Residential class's current share of total revenue and its cost-based revenue responsibility.[16] The table below, which is a reproduction of Schedule A4 to the Company's May 1, 2015 compliance filing, details the steps necessary to accomplish a movement to cost. First, the ordered revenue is allocated to classes equally, as shown in Columns E through G. This first step results in no movement to cost, as seen by comparing Columns A and E in the Percent of Retail portion of Schedule A4. The first step is necessary to provide a comparable revenue level to measure a given movement to cost. To accomplish a movement to cost, the cost-based revenue is compared to the revenue with an across the board increase, shown in Column H of Schedule A4. The appropriate movement to cost is then applied to arrive at the final revenue apportionment, as shown in Columns I through K.

Reproduction of Schedule A4 to May 1, 2015 Compliance Filing

	A	B	C	D	E	F	G	H	I	J	K	L	M
			B - A	C / A				B - E		H x I		F + J	L / A
	Present	Ordered Revenue at Cost			Revenue at Equal Increase			Cost	Cost Movement		Final Ordered Revenue		
	Revenue[(1)]	Total	Amt Incr	Pct Incr	Total	Amt Incr	Pct Incr	Difference	Percent	Amount	Total	Amt Incr	Pct Incr
Res	$1,023,121	$1,087,369	$64,248	6.28%	$1,083,849	$60,728	5.94%	$3,519	75%	$2,640	$1,086,489	$63,368	6.19%
Com	$108,086	$113,601	$5,514	5.10%	$114,502	$6,416	5.94%	-$901	100%	-$901	$113,601	$5,514	5.10%
All Dmd	$1,669,134	$1,767,681	$98,547	5.90%	$1,768,207	$99,073	5.94%	-$526	*Remainder Incr.*		$1,768,031	$98,897	5.93%
Ltg	$26,319	$25,789	-$530	-2.02%	$27,881	$1,562	5.94%	-$2,093	*Zero Incr.*		$26,319	$0	0.00%
Retail	$2,826,661	$2,994,440	$167,779	5.94%	$2,994,440	$167,779	5.94%	$0			$2,994,440	$167,779	5.94%
Other Incr		$306	$306								$306	$306	
Total	$2,826,661	$2,994,746	$168,085	5.95%							$2,994,746	$168,085	5.95%
InterDept	$962	$962									$962		
Total+ID	$2,827,623	$2,995,708	$168,085	5.94%							$2,995,708	$168,085	5.94%
Percent of Retail													
Res	36.20%	36.31%			36.20%			0.12%			36.28%	0.09%	
Com	3.82%	3.79%			3.82%			-0.03%			3.79%	-0.03%	
All Dmd	59.05%	59.03%			59.05%			-0.02%			59.04%	-0.01%	
Ltg	0.93%	0.86%			0.93%			-0.07%			0.88%	-0.05%	
Retail	100.00%	100.00%			100.00%			0.00%			100.00%	0.00%	

(1) Based on Jan-Dec 2014 Actuals (Weather-Normalized) with Year 2015 LCI Adjustment

It is important to note that the Company's proposed apportionment methodology is fully supported in the record. Company witness Mr. Steven Huso explained in his Direct Testimony that any given apportionment includes two factors: the portion of the apportionment attributable to the change in revenue requirement (i.e. the increase if there was no change in apportionment) and the portion of the apportionment attributable to changes in rate design (i.e. a movement to cost).[17] The Company has

---

16 36.31% (cost-based revenue responsibility) – 36.20% (current revenue share) = 0.11% (distance from cost). 0.11% (distance from cost) * 75% = 0.08%. 36.20% + 0.08% = 36.28% (Company's proposed apportionment for the Residential class).

17 Ex. 105, Huso Direct at 10-12.

used this approach in this and several other rate cases. Abandoning the first step (as occurs in the "PUC Methodology" from the Departments' Table 2) is not a "slightly modified version of the apportionment method described by the Company"[18] – it is a fundamental change that was not discussed or assessed in the record of this case.

We ask that the Commission clarify the language on Page 84 of the May 8, 2015 Order. We also ask that the Commission affirm that the approach detailed in Schedule A4 to the Company's May 1, 2015 compliance filing is the appropriate process for accomplishing a given movement to cost and that the Company has correctly implemented Order Point 48. Finally, we ask the Commission to adopt the revenue apportionment shown on Attachment J, which reflects the revised 2015 CCOSS.

REPLY TO THE OAG'S INTERIM RATE REFUND CALCULATION COMMENTS

For this rate case, the Company is requesting to apply the Commission's historic interim rate methods to an MYRP by treating the entire period that interim rates are in effect as the "interim rate period"[19] and calculating the interim rate refund due based on the final rates approved by the Commission during the interim rate period. The Company's past filings have demonstrated both the reasonableness of our interim rate proposal as well as how it best applies the Interim Rate Statute (Minn. Stat. § 216B.16, subd. 3) to the first MYRP rate case in Minnesota.[20] Our proposal is consistent with the law, with the methods used in prior rate cases, and with "the purpose of the interim rate period [] to prevent the 'potentially confiscatory effect of regulatory delay.'"[21] In light of this, the Company's interim rate proposal is appropriate and should be accepted by the Commission.

The OAG raises new issues on compliance with respect to the calculation of the interim rate refund under the Company's interim rate refund proposal.[22] More

---

[18] May 8, 2015 Order at 84.

[19] *See, e.g.*, Order Setting Interim Rates, Docket No. E-002,/GR-13-868 at ¶5 (Jan. 2, 2014) ("[t]hroughout the interim rate period, the Company shall display the interim rate increase on customers' bills using a single line-interim interim rate adjustment") (emphasis added); *In re Minnegasco*, Docket No. G-008/GR-93-1090, 1995 WL 638618 (Sept. 29, 1995) ("Minnegasco's evaluations of CCRC revenues collected during the interim rate period began on February 1, 1994, and will end on the date that Minnegasco implements final rates") (emphasis added).

[20] *See* Compliance Filing Related to Interim Rate Refund, Docket No. E-002/GR-13-868 (April 30, 2015) ("April 30, 2015 Compliance Filing").

[21] *In re Petition of Minnesota Power & Light Company*, 325 N.W.2d 550, 555 (Minn. Ct. App. 1989).

[22] Comments of the Office of Attorney General – Residential Utilities and Antitrust Division, Docket No. E-002/GR-13-868 (May 28, 2015) ("OAG Comments").

specifically, the OAG raises (1) concerns that we have incorrectly calculated the interest due on the interim rate refund; and (2) concerns with the use of billing month data for the calculation of the interim rate refund. We do not believe these concerns are well founded as they are merely the result of calculating the interim rate refund consistent with the law and past practice. Consequently, the Commission need not address the additional issues argued by the OAG. For the sake of convenience, we provide additional information in response to the OAG here.

1. *Interest is Appropriately Applied*

The OAG argues that the Company's interim rate proposal will not allow for the proper calculation of interest for our interim rate refund as it would reduce the balance on which interest is applied in 2015.[23] This is simply incorrect. Our calculation of the applicable balances upon which to apply interest is just the mathematical outcome of the proper application of the Interim Rate Statute.

Under the Interim Rate Statute, "the utility [is required] to refund the excess amount collected under the interim rate schedule" during the interim rate period. As demonstrated in our April 30, 2015 Compliance Filing, there is a single interim rate period applicable to this case and there is only one interim rate schedule in effect during the interim rate period. Therefore, to properly calculate the "excess amount collected" we determine the difference in revenue we collected through interim rates during the interim rate period and the Commission's authorized rates for the same period.

In a single test year case, this calculation is simply applying final rates to sales and netting it against the actual interim rates collected. However, because this case is the first MYRP in Minnesota, we must now account for the change in final authorized rates from 2014 to 2015. The Schedules of our April 30, 2015 Compliance Filing perform this calculation.

Upon review of our calculations, the OAG now raises concerns with the fact that in calculating the "excess amount collected" under interim rates, balances are declining in 2015 to account for the MYRP nature of this rate case and the Commission's final determination on rates. The OAG does not argue that we have incorrectly calculated the interim rate refund consistent with the Interim Rate Statute and past practice. Rather, the OAG raises concerns about the outcome of this calculation. The OAG is

[23] OAG Comments at 9-10.

now requesting that the mathematical application of the Interim Rate Statute should be manipulated. We submit that this is inappropriate.

Further, the OAG's preferred mathematical outcome only makes sense if the interim rate period is treated as two periods. However, that would also require that interim rates to have been adjusted in 2015 for the determination of the excess amount collected to be symmetrical. The Company did not make this request and therefore there is no need to deviate from the mechanical application of the Interim Rate Statute.

Our calculations are consistent with the treatment of the interim rate period as one single period as provided for by the Interim Rate Statute and past practice.[24] Our calculation also ensures that our customers are appropriately compensated for the time value of money while recognizing that "the purpose of the interim rate period is to prevent the 'potentially confiscatory effect of regulatory delay.'"[25] Consequently, the Commission should reject the OAG's proposal.

2. *Use of Billing Month Revenue is Appropriate*

The OAG also raises concerns with the Company's historic use of billing month data to calculate the interim rate refund.[26] The OAG essentially argues that the use of billing month data is insufficiently accurate to fully capture customers' usage on the days in which rate transition on January 1, 2015 and upon the Commission's final determination on May 8, 2015. The OAG believes that this would lead to over collection of interim rates during the interim rate period and, due to this, the OAG is requesting to calculate an estimated adjustment to the interim rates collected during the months surrounding these transitions. We believe that OAG's proposal would create additional inaccuracies in the calculation of the interim rate refunds that are inconsistent with the purpose of interim rates.

---

[24] Similarly, by determining the interim refund based on a single interim rate period, we are not surcharging customers prior to when permitted under the Interim Rate Statute. Instead, we are calculating the "excess amount collected" through interim rates as required by the Interim Rate Statute. The OAG's argument that our interim rate proposal would result in an impermissible surcharge assumes that the interim rate period must be considered as two separate periods. Without a symmetrical upward adjustment to interim rates in 2015, this would be contrary to the intent of interim rates to hold a utility harmless during the prosecution of a rate case. The Company's interim rate proposal is the only proposal before the Commission that gives full effect to the Interim Rate Statute. *In re Petition of Minnesota Power & Light*, 435 N.W.2d 550, 556 (Minn. 1989) (citing *Sandy v. Walter Butler Shipbuilders*, 21 N.W.2d 612 (1946)) (noting that in light of ambiguity, the entire Act should be construed so as to ascertain and effectuate its principle objective).

[25] *In re Petition of Minnesota Power & Light Company*, 325 N.W.2d 550, 555 (Minn. Ct. App. 1989).

[26] OAG Comments at 11-12.

We have always used billing month data to calculate the interim rate refund because this is the most accurate data available. However, because we do not bill customers on the first of the month each month, billing month data includes usage that occurred in more than one month. We cannot provide a summary of actual bills on a calendar month basis. Instead we would have to estimate how much usage on the bills was related to the prior month. Therefore, we use billing month data as the best available data set to most accurately capture customers' actual usage.

The OAG now argues that additional adjustments are necessary to account for the use of billing month data to calculate the interim rate refund when rates change from 2014 final rates to 2015 final rates and in the month of the Commission's final determination (May, 2015). Unfortunately, precise data to perfectly calculate customers' usage around these dates does not exist and would have to be estimated. Therefore, accepting the OAG's proposal would ultimately result in less accurate calculation of "excess amount collected" under interim rates to "increase the amount of the 2014 over-collection."[27] We do not believe this justifies a departure from using the most accurate data available.

Additionally, when the refund actually occurs, the final refund factor is applied to each customer's actual monthly bills that are on a billing month basis. Therefore using a summary of billing month interim revenue is most appropriate, since it more accurately reflects how the refund will be applied in practice.

CONCLUSION

The Company appreciates the opportunity to comment further on the compliance CCOSS, revenue apportionment and the calculations of the interim rate refund. We also appreciate the Department's review and have made corrections to the compliance CCOSS. We ask that the corrected compliance CCOSSs and the Company's associated updated revenue apportionment be adopted, and that the OAG's proposed changes to the interim refund calculations be rejected.

Dated: June 8, 2015

Northern States Power Company

[27] OAG Comments at 12.

Summary of 2014 Compliance Class Cost of Service Study Results ($000) | Attachment A - Page 1 of 15

PUBLIC DOCUMENT
TRADE SECRET INFORMATION AND NON-PUBLIC DATA EXCISED

UNADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[1]	Unadjusted Rate Revenue Reqt (CCOSS page 2, line 1)	2,884,839	1,048,450	107,903	1,704,167	24,320
[2]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	107	78	5	24	0
[3]	Unadjusted Operating Revenues (line 1 + line 2)	2,884,946	1,048,528	107,908	1,704,191	24,320
[4]	Present Rates (CCOSS page 2, line 2)	2,826,039	1,023,255	108,102	1,668,360	26,321
[5]	Unadjusted Deficiency (line 3 - line 4)	58,908	25,273	(194)	35,831	(2,001)
[6]	Defic / Pres (line 5 / line 4)	2.1%	2.5%	-0.2%	2.1%	-7.6%
[7]	**Ratio: Class % / Total %**	**1.00**	**1.18**	**-0.09**	**1.03**	**-3.65**

COST RESPONSIBILITIES FOR RATE DISCOUNTS

		Total	Residential	Non-Demand	Demand	Street Ltg
		[TRADE SECRET BEGINS				
[8]	Rate Discounts (CCOSS page 2, line 5)					
[9]	Rate Discount Cost Allocation (CCOSS page 2, line 6)					
						TRADE SECRET ENDS]
[10]	Revenue Requirement Change (line 9 - line 8)	0	(630)	1,809	(1,193)	13

ADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[11]	Adjusted Rate Revenue Reqt (line 1 + line 10)	2,884,839	1,047,820	109,712	1,702,974	24,332
[12]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	107	78	5	24	0
[13]	Adjusted Operating Revenues (line 11 + line 12)	2,884,946	1,047,899	109,717	1,702,998	24,333
[14]	Present Rates (line 4)	2,826,039	1,023,255	108,102	1,668,360	26,321
[15]	Adjusted Deficiency (line 13 - line 14)	58,908	24,643	1,615	34,638	(1,989)
[16]	Defic / Pres Rates (line 15 / line 14)	2.1%	2.4%	1.5%	2.1%	-7.6%
[17]	**Ratio: Class % / Total %**	**1.00**	**1.16**	**0.72**	**1.00**	**-3.62**

			1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
	Rate Base											
	Plant In Service	Alloc	MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
1	Production		7,952,587	2,441,893	5,485,732	273,150	5,212,582	3,769,501	976,574	452,078	14,429	24,961
2	Transmission		1,999,647	692,066	1,307,404	74,001	1,233,404	907,730	235,031	87,453	3,189	176
3	Distribution		3,019,971	1,968,098	950,900	141,788	809,113	682,441	90,448	36,174	49	100,972
4	General		954,469	375,399	569,791	35,975	533,816	394,354	95,803	42,359	1,300	9,279
5	Common		0	0	0	0	0	0	0	0	0	0
6	Total Plant In Service		13,926,673	5,477,457	8,313,828	524,913	7,788,914	5,754,027	1,397,856	618,064	18,968	135,389
7	Production		4,452,332	1,355,704	3,081,790	152,134	2,929,655	2,115,614	548,111	257,792	8,139	14,838
8	Transmission		566,977	196,696	370,264	21,015	349,249	257,200	66,594	24,553	902	16
9	Distribution		1,184,482	755,501	366,714	54,493	312,221	262,719	34,808	14,673	21	62,268
10	General		422,837	166,305	252,421	15,937	236,484	174,702	42,441	18,765	576	4,111
11	Common		0	0	0	0	0	0	0	0	0	0
12	Total Depreciation Reserve		6,626,627	2,474,206	4,071,189	243,579	3,827,610	2,810,234	691,955	315,784	9,637	81,233
13	**Net Plant In Service**		7,300,046	3,003,252	4,242,639	281,334	3,961,305	2,943,793	705,901	302,280	9,331	54,156
14	Deducts: Accum Defer Inc Tax		1,604,790	671,417	925,868	62,580	863,288	642,704	152,849	65,715	2,020	7,505
15	Constr Work In Progress		530,071	177,962	349,809	18,797	331,013	240,955	61,441	27,749	869	2,300
16	Fuel Inventory		74,663	21,829	52,516	2,488	50,028	35,892	9,300	4,695	141	317
17	Materials & Supplies		116,514	39,387	76,485	4,142	72,343	52,680	13,369	6,101	192	641
18	Prepayments		164,602	67,717	95,663	6,344	89,320	66,377	15,917	6,816	210	1,221
19	Non-Plant & Work Cash		(87,457)	(35,849)	(50,664)	(3,392)	(47,272)	(35,126)	(8,420)	(3,615)	(112)	(944)
20	Total Additions		798,392	271,047	523,810	28,379	495,431	360,778	91,606	41,746	1,301	3,536
21	**Rate Base**		6,493,648	2,602,881	3,840,580	247,133	3,593,448	2,661,867	644,658	278,311	8,612	50,186
	Income Statement											
22A	**Tot Oper Rev - Pres**		3,448,403	1,221,641	2,198,452	129,830	2,068,622	1,541,435	358,517	162,948	5,723	28,311
22B	**Tot Oper Rev - Prop**		3,507,311	1,243,010	2,235,442	132,084	2,103,359	1,567,483	364,418	165,638	5,819	28,859
23	Oper & Maint		2,442,086	817,709	1,609,019	89,032	1,519,987	1,107,625	281,585	126,654	4,123	15,357
24	Book Depr + IRS Int		273,308	101,277	168,297	10,022	158,274	115,853	28,692	13,337	391	3,734
25	Payroll, RI Est & Prop Tax		183,763	75,239	106,547	7,128	99,418	73,862	17,715	7,606	235	1,977
26	Deferred Inc Tax & Net ITC		161,968	72,379	88,045	6,530	81,515	61,623	14,403	5,312	177	1,544
27A	Present Income Tax		(19,954)	(9,324)	(11,632)	108	(11,740)	2,241	(11,043)	(3,034)	96	1,002
27B	Proposed Income Tax		4,416	(483)	3,671	1,041	2,630	13,018	(8,602)	(1,922)	136	1,228
28	Allow Funds Dur Const		34,864	11,875	22,829	1,244	21,584	15,744	4,006	1,778	56	160
29A	**Present Return**		442,096	176,234	261,005	18,253	242,752	195,974	31,170	14,851	756	4,857
29B	**Proposed Return**		476,634	188,763	282,693	19,575	263,118	211,247	34,630	16,428	813	5,178
30A	**Pres Ret on Rt Base**		6.81%	6.77%	6.80%	7.39%	6.76%	7.36%	4.84%	5.34%	8.78%	9.68%
30B	**Prop Ret on Rt Base**		**7.34%**	7.25%	7.36%	7.92%	7.32%	7.94%	5.37%	5.90%	9.44%	10.32%
31A	**Pres Ret on Common**		8.70%	8.63%	8.68%	9.80%	8.60%	9.76%	4.94%	5.90%	12.47%	14.17%
31B	**Prop Ret on Common**		**9.71%**	9.55%	9.75%	10.82%	9.68%	10.85%	5.97%	6.98%	13.71%	15.39%

PRES vs Equal Rev Reqts

			1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	**UnAdj Equal Rev Reqt @ 7.34%**		**2,884,839**	**1,048,450**	**1,812,070**	**107,903**	**1,704,167**	**1,249,947**	**311,039**	**138,766**	**4,414**	**24,320**
2	**Present Revenue**		**2,826,039**	**1,023,255**	**1,776,462**	**108,102**	**1,668,360**	**1,250,979**	**283,500**	**129,254**	**4,626**	**26,321**
3	**UnAdj Revenue Deficiency**		**58,800**	**25,194**	**35,608**	**(199)**	**35,807**	**(1,032)**	**27,539**	**9,512**	**(212)**	**(2,002)**
4	**UnAdj Deficiency / Present**		**2.08%**	**2.46%**	**2.00%**	**-0.18%**	**2.15%**	**-0.08%**	**9.71%**	**7.36%**	**-4.59%**	**-7.60%**
			[TRADE SECRET BEGINS									
5	**Pres Rate Discounts**											
6	**Pres Rate Discount Cost Alloc**	**DiscAlloc**										
											TRADE SECRET ENDS]	
7	**Revenue Requirement Shift**		**0**	**(630)**	**617**	**1,809**	**(1,193)**	**7,922**	**(1,319)**	**(7,581)**	**(214)**	**13**
8	**Adj Equal Rev Reqt (Rows 1+7)**		**2,884,839**	**1,047,820**	**1,812,686**	**109,712**	**1,702,974**	**1,257,870**	**309,720**	**131,185**	**4,200**	**24,332**
9	**Adj Rev Defic vs Pres Rev (Row 2)**		**58,800**	**24,565**	**36,224**	**1,610**	**34,614**	**6,890**	**26,220**	**1,931**	**(427)**	**(1,989)**
10	**Adj Deficiency / Adj Present**		**2.08%**	**2.40%**	**2.04%**	**1.49%**	**2.07%**	**0.55%**	**9.25%**	**1.49%**	**-9.22%**	**-7.56%**
	Equal Customer Classification											
11	Min Sys & Service Drop		190,995	155,836	19,593	11,461	8,132	7,757	341	27	7	15,566
12	Energy Services		57,740	47,690	9,662	5,523	4,139	4,070	64	3	2	388
13	Total Customer **(Cusco)**		248,734	203,526	29,254	16,984	12,270	11,827	404	30	9	15,954
14	Ave Monthly Customers		1,272,915	1,113,587	132,467	86,824	45,642	45,146	469	17	10	26,861
15	Svc Drop Reqt	$ / Mo / Cust	$12.50	$11.66	$12.33	$11.00	$14.85	$14.32	$60.60	$128.10	$60.90	$48.29
16	Ener Svcs Reqt	$ / Mo / Cust	$3.78	$3.57	$6.08	$5.30	$7.56	$7.51	$11.30	$15.14	$15.14	$1.21
17	Total Reqt	$ / Mo / Cust	$16.28	$15.23	$18.40	$16.30	$22.40	$21.83	$71.91	$143.24	$76.04	$49.50
	Equal Energy Classification											
18	On Peak Rev Reqt		745,510	203,076	541,044	28,602	512,442	374,022	94,283	42,747	1,389	1,390
19	Off Peak Rev Reqt		690,652	216,465	469,369	19,239	450,130	318,396	84,491	45,899	1,345	4,817
20	Total Ener Rev Reqt		1,436,162	419,541	1,010,413	47,842	962,572	692,417	178,774	88,646	2,734	6,207
21	Annual MWh Sales		30,758,207.855	8,756,626	21,827,703	968,021	20,859,682	14,754,374	3,932,785	2,111,112	61,411	173,879
22	On Pk Reqt	Mills / kWh	24.238	23.191	24.787	29.547	24.566	25.350	23.974	20.249	22.620	7.995
23	Off Pk Reqt	Mills / kWh	22.454	24.720	21.503	19.875	21.579	21.580	21.484	21.741	21.895	27.704
24	Total Reqt	Mills / kWh	46.692	47.911	46.290	49.422	46.145	46.930	45.457	41.990	44.515	35.698
	Equal Demand Classification											
25	Energy-Related Prod		244,522	73,671	169,986	8,306	161,681	116,587	30,207	14,436	451	865
26	Capacity-Related Summer Peak Prod		384,512	132,509	251,840	14,204	237,636	176,558	45,389	15,061	629	164
27	Capacity-Related Winter Peak Prod		143,851	49,573	94,217	5,314	88,903	66,053	16,981	5,634	235	61
28	Total Capacity-Related Prod		528,364	182,082	346,056	19,517	326,539	242,610	62,370	20,695	864	226
29	Total Production		772,885	255,753	516,043	27,823	488,219	359,197	92,576	35,131	1,315	1,090
30	Transmission **(Transco)**		223,966	77,625	146,334	8,301	138,033	101,655	26,325	9,696	357	7
31	Primary Dist Subs		76,512	28,730	47,326	2,596	44,730	31,488	7,980	5,263	0	456
32	Prim Dist Lines		56,287	28,032	27,923	1,827	26,097	21,117	4,980	0	0	332
33	Second Dist, Trans		70,292	35,243	34,776	2,530	32,246	32,246	0	0	0	273
34	Total Distribution **(Disco)**		203,091	92,004	110,025	6,952	103,073	84,851	12,959	5,263	0	1,061
35	Total Demand Rev Reqt		1,199,942	425,382	772,402	43,077	729,325	545,703	131,860	50,090	1,671	2,158
36	Annual Billing kW		53,267,029	0	53,267,029	0	53,267,029	40,423,684	8,517,989	4,077,194	248,162	0
37	Base Rev Reqt	$ / kW	$0.00	$0.00	$3.19	$0.00	$3.04	$2.88	$3.55	$3.54	$1.82	$0.00
38	Summer Rev Reqt	$ / kW	$0.00	$0.00	$4.73	$0.00	$4.46	$4.37	$5.33	$3.69	$2.53	$0.00
39	Winter Rev Reqt	$ / kW	$0.00	$0.00	$1.77	$0.00	$1.67	$1.63	$1.99	$1.38	$0.95	$0.00
40	Prod Rev Reqt	$ / kW	$0.00	$0.00	$9.69	$0.00	$9.17	$8.89	$10.87	$8.62	$5.30	$0.00
41	Tran Rev Reqt	$ / kW	$0.00	$0.00	$2.75	$0.00	$2.59	$2.51	$3.09	$2.38	$1.44	$0.00
42	Dist Rev Reqt	$ / kW	$0.00	$0.00	$2.07	$0.00	$1.94	$2.10	$1.52	$1.29	$0.00	$0.00
43	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$14.50	$0.00	$13.69	$13.50	$15.48	$12.29	$6.74	$0.00
44	Tot Dmd Rev Reqt	Mills / kWh	39.012	48.578	35.386	44.500	34.963	36.986	33.528	23.727	27.217	12.411
45	Summer Billing kW		19,423,061	0	19,423,061	0	19,423,061	14,775,201	3,164,410	1,392,494	90,956	0
46	Winter Billing kW		33,843,967	0	33,843,967	0	33,843,967	25,648,483	5,353,579	2,684,700	157,205	0
47	Tot Summer Reqt	$ / kW	$0.00	$0.00	$20.97	$0.00	$19.80	$19.45	$22.50	$18.03	$10.17	$0.00
48	Tot Winter Reqt	$ / kW	$0.00	$0.00	$10.79	$0.00	$10.19	$10.07	$11.33	$9.31	$4.75	$0.00
49	Energy + Production **(Genco)**		2,209,047	675,294	1,526,456	75,665	1,450,791	1,051,614	271,351	123,777	4,048	7,297

			1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	**Proposed Ret On Rt Base**		**7.34%**	**7.25%**	**7.36%**	**7.92%**	**7.32%**	**7.94%**	**5.37%**	**5.90%**	**9.44%**	**10.32%**
2	**UnAdj Equalized Rev Reqt**		**2,884,839**	**1,048,450**	**1,812,070**	**107,903**	**1,704,167**	**1,249,947**	**311,039**	**138,766**	**4,414**	**24,320**
3	**Proposed Revenue**		**2,884,839**	**1,044,546**	**1,813,424**	**110,351**	**1,703,073**	**1,277,008**	**289,399**	**131,943**	**4,723**	**26,869**
4	**UnAdj Revenue Deficiency**		**0**	**3,904**	**(1,354)**	**(2,448)**	**1,094**	**(27,060)**	**21,640**	**6,823**	**(308)**	**(2,549)**
5	**UnAdj Deficiency / Proposed**		**0.00%**	**0.37%**	**-0.07%**	**-2.22%**	**0.06%**	**-2.12%**	**7.48%**	**5%**	**-7%**	**-9.49%**
6	**Prop Rate Discounts**		**171,636**	**56,138**	**114,775**	**4,879**	**109,896**	**71,891**	**21,370**	**16,104**	**531**	**724**
7	**Prop Rate Discount Cost Alloc**	**DiscAlloc**	**171,636**	**59,868**	**111,736**	**6,393**	**105,344**	**78,055**	**20,165**	**6,850**	**274**	**31**
8	**Revenue Requirement Shift**		**0**	**3,731**	**(3,038)**	**1,514**	**(4,552)**	**6,164**	**(1,205)**	**(9,254)**	**(257)**	**(693)**
9	**Adj Equal Rev (Rows 2+8)**		**2,884,839**	**1,052,180**	**1,809,032**	**109,417**	**1,699,615**	**1,256,111**	**309,834**	**129,512**	**4,157**	**23,627**
10	**Adj Rev Defic vs Prop Rev (Row 3)**		**0**	**7,634**	**(4,392)**	**(935)**	**(3,458)**	**(20,897)**	**20,436**	**(2,431)**	**(566)**	**(3,242)**
11	**Adj Deficiency / Adj Prop**		**0.00%**	**0.73%**	**-0.24%**	**-0.85%**	**-0.20%**	**-1.64%**	**7.06%**	**-1.84%**	**-11.98%**	**-12.07%**
	Prop Customer Component											
12	Min Sys & Service Drop		188,705	151,608	19,825	11,662	8,163	7,832	299	24	8	17,272
13	Energy Services		57,742	47,692	9,662	5,523	4,139	4,070	64	3	2	388
14	Total Customer **(Cusco)**		246,447	199,301	29,486	17,184	12,302	11,902	363	28	9	17,660
15	Ave Monthly Customers		1,272,915	1,113,587	132,467	86,824	45,642	45,146	469	17	10	26,861
16	Svc Drop Reqt	$ / Mo / Cust	$12.35	$11.35	$12.47	$11.19	$14.90	$14.46	$53.24	$116.03	$65.25	$53.58
17	Ener Svcs Reqt	$ / Mo / Cust	$3.78	$3.57	$6.08	$5.30	$7.56	$7.51	$11.31	$15.14	$15.14	$1.20
18	Total Reqt	$ / Mo / Cust	$16.13	$14.91	$18.55	$16.49	$22.46	$21.97	$64.54	$131.17	$80.38	$54.79
	Prop Energy Component											
19	On Peak Rev Reqt		745,145	202,983	540,769	28,604	512,164	374,023	94,079	42,672	1,391	1,393
20	Off Peak Rev Reqt		690,303	216,366	469,109	19,241	449,868	318,397	84,308	45,817	1,346	4,828
21	Total Ener Rev Reqt		1,435,448	419,350	1,009,877	47,845	962,032	692,420	178,386	88,489	2,737	6,221
22	Annual MWh Sales		30,758,208	8,756,626	21,827,703	968,021	20,859,682	14,754,374	3,932,785	2,111,112	61,411	173,879
23	On Pk Reqt	Mills / kWh	24.226	23.181	24.774	29.549	24.553	25.350	23.922	20.213	22.647	8.011
24	Off Pk Reqt	Mills / kWh	22.443	24.709	21.491	19.876	21.566	21.580	21.437	21.703	21.921	27.766
25	Total Reqt	Mills / kWh	46.669	47.889	46.266	49.426	46.119	46.930	45.359	41.916	44.569	35.777
	Prop Demand Component											
26	Energy-Related Prod		253,912	77,027	175,394	9,568	165,827	133,300	20,824	11,069	633	1,491
27	Capacity-Related Summer Peak Prod		381,860	131,708	249,988	14,434	235,554	178,918	41,830	14,138	668	164
28	Capacity-Related Winter Peak Prod		142,859	49,274	93,524	5,400	88,124	66,936	15,649	5,289	250	61
29	Total Capacity-Related Prod		524,719	180,981	343,512	19,834	323,678	245,854	57,480	19,427	918	226
30	Total Production		778,631	258,008	518,906	29,401	489,505	379,155	78,304	30,496	1,551	1,717
31	Transmission **(Transco)**		223,640	77,757	145,876	8,810	137,066	107,161	21,220	8,260	425	7
32	Primary Dist Subs		75,766	28,562	46,656	2,686	43,970	32,426	6,873	4,671	0	548
33	Prim Dist Lines		55,191	27,382	27,421	1,852	25,569	21,316	4,253	0	0	388
34	Second Dist, Trans		69,716	34,186	35,201	2,573	32,628	32,628	0	0	0	329
35	Total Distribution **(Disco)**		200,673	90,130	109,278	7,111	102,167	86,370	11,126	4,671	0	1,265
36	Total Demand Rev Reqt		1,202,944	425,895	774,060	45,322	728,739	572,686	110,650	43,427	1,976	2,988
37	Annual Billing kW		53,267,029	0	53,267,029	0	53,267,029	40,423,684	8,517,989	4,077,194	248,162	0
38	Base Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$3.11	$3.30	$2.44	$2.71	$2.55	$0.00
39	Summer Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$4.42	$4.43	$4.91	$3.47	$2.69	$0.00
40	Winter Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$1.65	$1.66	$1.84	$1.30	$1.01	$0.00
41	Prod Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$9.19	$9.38	$9.19	$7.48	$6.25	$0.00
42	Tran Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$2.57	$2.65	$2.49	$2.03	$1.71	$0.00
43	Dist Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$1.92	$2.14	$1.31	$1.15	$0.00	$0.00
44	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$13.68	$14.17	$12.99	$10.65	$7.96	$0.00
45	Tot Dmd Rev Reqt	Mills / kWh	39.110	48.637	35.462	46.819	34.935	38.815	28.135	20.571	32.178	17.184
46	Summer Billing kW		19,423,061	0	19,423,061	0	19,423,061	14,775,201	3,164,410	1,392,494	90,956	0
47	Winter Billing kW		33,843,967	0	33,843,967	0	33,843,967	25,648,483	5,353,579	2,684,700	157,205	0
48	Tot Summer Reqt	$ / kW	$0.00	$0.00	$20.95	$0.00	$19.73	$20.19	$19.46	$16.04	$11.61	$0.00
49	Tot Winter Reqt	$ / kW	$0.00	$0.00	$10.85	$0.00	$10.21	$10.69	$9.17	$7.86	$5.85	$0.00
50	Energy + Production **(Genco)**		2,214,079	677,358	1,528,783	77,246	1,451,537	1,071,575	256,690	118,985	4,288	7,937
51	Prop Rev - Pres Rev (Pg 2)		58,800	21,290	36,962	2,249	34,713	26,029	5,899	2,689	96	548
52	Difference / Present		2.08%	2.08%	2.08%	2.08%	2.08%	2.08%	2.08%	2.08%	2.08%	2.08%

PUBLIC DOCUMENT
TRADE SECRET INFORMATION AND NON-PUBLIC DATA EXCISED

Original Plant in Service

				1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Summer Peak	D10S		1,513,292	527,447	985,845	56,332	929,513	688,570	178,313	60,218	2,413	0
2	WInter Peak	D10S		566,143	197,325	368,818	21,074	347,743	257,603	66,709	22,528	903	0
3	Total Peak	D10S		2,079,435	724,772	1,354,662	77,406	1,277,256	946,173	245,022	82,746	3,316	0
4	Base Load	E8760		4,000,703	1,169,677	2,814,023	133,338	2,680,685	1,923,209	498,322	251,584	7,570	17,003
5	Nuclear Fuel	E8760		1,872,449	547,444	1,317,047	62,406	1,254,641	900,119	233,230	117,749	3,543	7,958
6	Total	34.20%	120, 310-346	7,952,587	2,441,893	5,485,732	273,150	5,212,582	3,769,501	976,574	452,078	14,429	24,961
	Transmission												
7	Gen Step Up Base	E8760		41,471	12,125	29,170	1,382	27,788	19,936	5,166	2,608	78	176
8	Gen Step Up Peak	D10S		21,555	7,513	14,042	802	13,240	9,808	2,540	858	34	0
9	Total Gen Step Up			63,026	19,638	43,212	2,185	41,027	29,744	7,705	3,466	113	176
10	Bulk Transmission	D10S		1,929,256	672,428	1,256,828	71,816	1,185,012	877,839	227,326	76,770	3,077	0
11	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign		7,365	0	7,365	0	7,365	147	0	7,217	0	0
13	Total		350-359	1,999,647	692,066	1,307,404	74,001	1,233,404	907,730	235,031	87,453	3,189	176
	Distribution: Substations												
14	Generat Step Up	STRATH		3,095	930	2,155	105	2,050	1,477	383	185	6	11
15	Bulk Transmission	D10S		1,611	562	1,050	60	990	733	190	64	3	0
16	Distrib Function	D60Sub		511,898	199,154	309,595	17,971	291,624	217,296	55,145	19,183	0	3,149
17	Direct Assign	Dir Assign		16,927	0	16,927	0	16,927	339	0	16,588	0	0
18	Total		360-363	533,531	200,645	329,726	18,135	311,590	219,845	55,717	36,020	8	3,160
	Overhead Lines												
19	Primary Capacity 1 Phase	D61PS1Ph		91,191	69,706	20,795	3,223	17,572	15,576	1,996	0	0	691
20	Primary Capacity Multi Phase	D61PS		157,859	55,510	101,567	4,870	96,697	76,949	19,748	0	0	783
21	Primary Customer 1 Phase	C61PS1Ph		57,804	55,036	2,625	2,263	363	361	2	0	0	142
22	Primary Customer Multi Phase	C61PS		100,062	89,120	10,615	6,954	3,661	3,624	38	0	0	328
23	Total Primary			406,916	269,371	135,602	17,309	118,293	96,510	21,783	0	0	1,943
24	Second Capacity	D62SecL		99,059	47,802	50,839	3,663	47,176	47,176	0	0	0	418
25	Second Customer	C62Sec		99,984	89,084	10,573	6,951	3,622	3,622	0	0	0	328
26	Total Secondary			199,044	136,886	61,412	10,614	50,798	50,798	0	0	0	746
27	Street Lighting	DASL		35,236	0	0	0	0	0	0	0	0	35,236
28	Total		364,365	641,196	406,258	197,014	27,923	169,090	147,307	21,783	0	0	37,924
	Underground Lines												
29	Primary Capacity 1 Phase	D61PS1Ph		38,727	29,602	8,831	1,369	7,462	6,615	848	0	0	293
30	Primary Capacity Multi Phase	D61PS		61,451	21,609	39,538	1,896	37,642	29,955	7,687	0	0	305
31	Primary Customer 1 Phase	C61PS1Ph		189,302	180,238	8,598	7,411	1,187	1,181	6	0	0	466
32	Primary Customer Multi Phase	C61PS		300,385	267,536	31,865	20,874	10,991	10,878	113	0	0	984
33	Total Primary			589,865	498,985	88,832	31,549	57,283	48,629	8,654	0	0	2,047
34	Second Capacity	D62SecL		241,096	116,344	123,734	8,916	114,818	114,818	0	0	0	1,018
35	Second Customer	C62Sec		266,273	237,244	28,157	18,511	9,646	9,646	0	0	0	872
36	Total Secondary			507,369	353,588	151,891	27,427	124,464	124,464	0	0	0	1,890
37	Street Lighting	DASL		0	0	0	0	0	0	0	0	0	0
38	Total		366,367	1,097,233	852,573	240,723	58,976	181,747	173,093	8,654	0	0	3,938
	Line Transformers												
39	Primary	D61PS		19,623	6,900	12,625	605	12,020	9,565	2,455	0	0	97
40	Second Capacity	D62SecL		187,807	90,629	96,385	6,945	89,440	89,440	0	0	0	793
41	Second Customer	C62Sec		157,314	140,164	16,635	10,936	5,699	5,699	0	0	0	515
42	Total		368	364,744	237,693	125,646	18,487	107,159	104,704	2,455	0	0	1,406
	Services												
43	Second Capacity	D62NLL		63,698	46,021	17,677	1,576	16,101	16,101	0	0	0	0
44	Second Customer	C62NL		169,202	159,752	9,450	6,213	3,238	3,238	0	0	0	0
45	Total		369	232,900	205,773	27,127	7,789	19,338	19,338	0	0	0	0
46	Meters	C12WM	370	96,003	65,157	30,665	10,477	20,188	18,154	1,839	154	41	181
47	Street Lighting	Dir Assign	373	54,364	0	0	0	0	0	0	0	0	54,364
48	**Total Distribution**			3,019,971	1,968,098	950,900	141,788	809,113	682,441	90,448	36,174	49	100,972
49	**General & Common Plant**	PTD	303, 389-399	954,469	375,399	569,791	35,975	533,816	394,354	95,803	42,359	1,300	9,279
50	Prelim Elec Plant			13,926,673	5,477,457	8,313,828	524,913	7,788,914	5,754,027	1,397,856	618,064	18,968	135,389
51	TBT Investment	NEPIS		0	0	0	0	0	0	0	0	0	0
52	**Elec Plant in Serv**			13,926,673	5,477,457	8,313,828	524,913	7,788,914	5,754,027	1,397,856	618,064	18,968	135,389

	Accum Deprec; Net Plant			1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		961,016	334,955	626,061	35,774	590,287	437,276	113,237	38,241	1,532	0
2	Decom Int Peaking	D10S		0	0	0	0	0	0	0	0	0	0
3	Decom Int Baseload	E8760		0	0	0	0	0	0	0	0	0	0
4	Nuclear Fuel	E8760		1,668,310	487,760	1,173,459	55,602	1,117,857	801,986	207,803	104,911	3,157	7,090
5	Base Load	E8760		1,823,006	532,988	1,282,269	60,758	1,221,511	876,351	227,071	114,639	3,449	7,748
6	Total		108,111,115,120.5	4,452,332	1,355,704	3,081,790	152,134	2,929,655	2,115,614	548,111	257,792	8,139	14,838
	Transmission												
7	Gen Step Up Base	E8760		3,807	1,113	2,678	127	2,551	1,830	474	239	7	16
8	Gen Step Up Peak	D10S		1,979	690	1,289	74	1,215	900	233	79	3	0
9	Total Gen Step Up			5,786	1,803	3,967	201	3,766	2,730	707	318	10	16
10	Bulk Transmission	D10S		559,166	194,894	364,273	20,815	343,458	254,429	65,887	22,251	892	0
11	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign		2,025	0	2,025	0	2,025	40	0	1,984	0	0
13	Total		108,111,115,120.5	566,977	196,696	370,264	21,015	349,249	257,200	66,594	24,553	902	16
	Distribution												
14	Generat Step Up	STRATH		1,661	499	1,156	56	1,100	792	205	99	3	6
15	Bulk Transmission	D10S		645	225	420	24	396	294	76	26	1	0
16	Distrib Function	D60Sub		197,982	77,025	119,739	6,950	112,789	84,042	21,328	7,419	0	1,218
17	Direct Assign	Dir Assign		7,212	0	7,212	0	7,212	144	0	7,068	0	0
18	Total Substations			207,500	77,748	128,527	7,031	121,497	85,272	21,609	14,612	4	1,224
19	Overhead Lines	POL		241,775	153,187	74,288	10,529	63,759	55,545	8,214	0	0	14,300
20	Underground	PUL		415,438	322,804	91,143	22,330	68,814	65,537	3,277	0	0	1,491
21	Line Transformers	P68		144,270	94,016	49,698	7,312	42,386	41,415	971	0	0	556
22	Services	P69		92,372	81,613	10,759	3,089	7,670	7,670	0	0	0	0
23	Meters	C12WM		38,503	26,132	12,299	4,202	8,097	7,281	738	62	17	73
24	Street Lighting	P73		44,624	0	0	0	0	0	0	0	0	44,624
25	Total		108,111,115,120.5	1,184,482	755,501	366,714	54,493	312,221	262,719	34,808	14,673	21	62,268
26	**General Plant**	PTD	108,111,115,120.5	422,837	166,305	252,421	15,937	236,484	174,702	42,441	18,765	576	4,111
27	**Electric Common**	PTD	108,111,115,120.5	0	0	0	0	0	0	0	0	0	0
28	**Total Accum Depr**			6,626,627	2,474,206	4,071,189	243,579	3,827,610	2,810,234	691,955	315,784	9,637	81,233
29	**Net Elec Plant**			7,300,046	3,003,252	4,242,639	281,334	3,961,305	2,943,793	705,901	302,280	9,331	54,156
30	**Net Plant w/ TBT**			7,300,046	3,003,252	4,242,639	281,334	3,961,305	2,943,793	705,901	302,280	9,331	54,156
	Subtractions: Accum Defer Inc Tax												
	Production												
31	Peaking Plant	D10S		248,067	86,462	161,605	9,234	152,371	112,874	29,230	9,871	396	0
32	Base Load	E8760		625,215	182,793	439,765	20,838	418,927	300,552	77,876	39,317	1,183	2,657
33	Nuclear Fuel	E8760		37,373	10,927	26,287	1,246	25,042	17,966	4,655	2,350	71	159
34	Total		190,281,282,283	910,655	280,181	627,657	31,317	596,340	431,392	111,761	51,538	1,649	2,816
	Transmission												
35	Gen Step Up Base	E8760		11,599	3,391	8,158	387	7,772	5,576	1,445	729	22	49
36	Gen Step Up Peak	D10S		6,029	2,101	3,927	224	3,703	2,743	710	240	10	0
37	Total Gen Step Up			17,627	5,492	12,086	611	11,475	8,319	2,155	969	32	49
38	Bulk Transmission	D10S		360,295	125,578	234,717	13,412	221,305	163,939	42,454	14,337	575	0
39	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
40	Direct Assign	Dir Assign		1,402	0	1,402	0	1,402	28	0	1,374	0	0
41	Total		281,282,283	379,324	131,070	248,205	14,023	234,182	172,286	44,609	16,681	606	49
	Distribution												
42	Generat Step Up	STRATH		576	173	401	20	381	275	71	34	1	2
43	Bulk Transmission	D10S		228	80	149	9	140	104	27	9	0	0
44	Distrib Function	D60Sub		85,862	33,404	51,929	3,014	48,915	36,448	9,250	3,218	0	528
45	Direct Assign	Dir Assign		2,146	0	2,146	0	2,146	43	0	2,103	0	0
46	Total Substations			88,812	33,657	54,625	3,042	51,582	36,869	9,348	5,364	1	530
47	Overhead Lines	POL		102,744	65,098	31,569	4,474	27,095	23,604	3,490	0	0	6,077
48	Underground	PUL		203,254	157,932	44,592	10,925	33,667	32,064	1,603	0	0	729
49	Line Transformers	P68		65,367	42,597	22,517	3,313	19,204	18,764	440	0	0	252
50	Services	P69		35,312	31,199	4,113	1,181	2,932	2,932	0	0	0	0
51	Meters	C12WM		18,242	12,381	5,827	1,991	3,836	3,449	349	29	8	34
52	Street Lighting	P73		(1,744)	0	0	0	0	0	0	0	0	(1,744)
53	Total		281,282,283	511,986	342,864	163,242	24,926	138,316	117,683	15,231	5,393	9	5,879
54	**General & Common Plant**	PTD	281,282,283	98,673	38,809	58,905	3,719	55,186	40,768	9,904	4,379	134	959
55	**Total Deferred Tax**			1,900,638	792,925	1,098,009	73,986	1,024,024	762,129	181,505	77,991	2,399	9,704
56	Net Operating Loss (NOL) Carry	NEPIS		(291,002)	(119,719)	(169,125)	(11,215)	(157,910)	(117,349)	(28,139)	(12,050)	(372)	(2,159)
57	Non-Plant Related	LABOR		(4,846)	(1,789)	(3,017)	(191)	(2,826)	(2,077)	(517)	(226)	(7)	(39)
58	**Accum Def W/ Adj**			1,604,790	671,417	925,868	62,580	863,288	642,704	152,849	65,715	2,020	7,505

	Additions: CWIP, Etc; Rate Base			1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		48,959	17,064	31,895	1,822	30,072	22,277	5,769	1,948	78	0
2	Base Load	E8760		195,394	57,127	137,437	6,512	130,924	93,929	24,338	12,287	370	830
3	Nuclear Fuel	E8760		109,627	32,051	77,109	3,654	73,456	52,699	13,655	6,894	207	466
4	Total		107	353,980	106,243	246,441	11,988	234,452	168,906	43,762	21,129	655	1,296
	Transmission												
5	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10S		0	0	0	0	0	0	0	0	0	0
7	Total Gen Step Up			0	0	0	0	0	0	0	0	0	0
8	Bulk Transmission	D10S		86,176	30,036	56,140	3,208	52,932	39,211	10,154	3,429	137	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
11	Total		107	86,176	30,036	56,140	3,208	52,932	39,211	10,154	3,429	137	0
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub		16,014	6,230	9,685	562	9,123	6,798	1,725	600	0	99
15	Direct Assign	Dir Assign		120	0	120	0	120	2	0	117	0	0
16	Total Substations			16,134	6,230	9,805	562	9,243	6,800	1,725	718	0	99
17	Overhead Lines	POL		2,526	1,601	776	110	666	580	86	0	0	149
18	Underground	PUL		15,413	11,976	3,381	828	2,553	2,431	122	0	0	55
19	Line Transformers	P68		50	33	17	3	15	14	0	0	0	0
20	Services	P69		(76)	(67)	(9)	(3)	(6)	(6)	0	0	0	0
21	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73		158	0	0	0	0	0	0	0	0	158
23	Total		107	34,205	19,772	13,971	1,501	12,470	9,820	1,933	718	0	462
24	**General Plant**	PTD	107	55,710	21,911	33,257	2,100	31,158	23,018	5,592	2,472	76	542
25	**Electric Common**	PTD	107	0	0	0	0	0	0	0	0	0	0
26	**Total CWIP**			530,071	177,962	349,809	18,797	331,013	240,955	61,441	27,749	869	2,300
27	Fuel Inventory	E8760	151,152	74,663	21,829	52,516	2,488	50,028	35,892	9,300	4,695	141	317
	Materials & Supplies												
28	Production	P10		100,313	30,802	69,196	3,445	65,751	47,548	12,318	5,702	182	315
29	Trans & Distr	TD		16,201	8,586	7,289	696	6,592	5,132	1,050	399	10	326
30	Total		154	116,514	39,387	76,485	4,142	72,343	52,680	13,369	6,101	192	641
	Prepayments												
31	Miscellaneous	NEPIS		164,602	67,717	95,663	6,344	89,320	66,377	15,917	6,816	210	1,221
32	Total		235,252,165	164,602	67,717	95,663	6,344	89,320	66,377	15,917	6,816	210	1,221
33	Non-Plant Assets & Liab	LABOR	190,283,	(13,137)	(4,851)	(8,180)	(518)	(7,662)	(5,630)	(1,401)	(612)	(20)	(107)
34	Working Cash	PT0	calculated	(74,320)	(30,999)	(42,485)	(2,874)	(39,611)	(29,496)	(7,020)	(3,003)	(92)	(837)
35	**Total Additions**			798,392	271,047	523,810	28,379	495,431	360,778	91,606	41,746	1,301	3,536
36	**Total Rate Base**			6,493,648	2,602,881	3,840,580	247,133	3,593,448	2,661,867	644,658	278,311	8,612	50,186
37	**Common Rate Base (@ 52.50%)**			3,409,165	1,366,513	2,016,305	129,745	1,886,560	1,397,480	338,446	146,113	4,521	26,348

	Operating Rev (Cal Month)			1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
	Retail Revenue	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Present Rate Revenue	R01; (calc)	440, 442,444,445	2,826,039	1,023,255	1,776,462	108,102	1,668,360	1,250,979	283,500	129,254	4,626	26,321
2	Proposed Rate Revenue	PROREV; (calc)		2,884,839	1,044,546	1,813,424	110,351	1,703,073	1,277,008	289,399	131,943	4,723	26,869
3	Equal Rate Revenue			2,884,839	1,048,450	1,812,070	107,903	1,704,167	1,249,947	311,039	138,766	4,414	24,320
	Other Retail Revenue												
4	Interdepartmental	R01; R02	448	962	348	605	37	568	426	97	44	2	9
5	Gross Earnings Tax	R01; R02	408	0	0	0	0	0	0	0	0	0	0
6	CIP Adjustment to Program Cost	E99XCIP	456	0	0	0	0	0	0	0	0	0	0
7	**Tot Other Retail Rev**			962	348	605	37	568	426	97	44	2	9
	Other Operating Revenue												
8	Interchg Prod Capacity	P10	456	198,304	60,891	136,791	6,811	129,980	93,996	24,352	11,273	360	622
9	Interchg Prod Energy	E8760	456	175,944	51,440	123,756	5,864	117,892	84,579	21,915	11,064	333	748
10	Interchg Tr Bulk Supply	D10S	456	41,350	14,412	26,938	1,539	25,398	18,815	4,872	1,645	66	0
11	PI Monti Return Adj-Peaking	D10S		544	189	354	20	334	247	64	22	1	0
12	PI Monti Return Adj-Baseload	E8760		2,303	673	1,620	77	1,543	1,107	287	145	4	10
13	Dist Int Sales; Oth Serv	E8760	412,451,456	652	191	458	22	437	313	81	41	1	3
14	Dist Overhd Line Rent	POL	454	3,634	2,302	1,117	158	958	835	123	0	0	215
15	Connection Charges	C11	451	2,173	1,901	226	148	78	77	1	0	0	46
16	Sales For Resale	E8760	447	78,571	22,972	55,266	2,619	52,647	37,771	9,787	4,941	149	334
17	Joint Op Agree-Other PSCo Rev	D10S	456	(4,827)	(1,682)	(3,145)	(180)	(2,965)	(2,196)	(569)	(192)	(8)	0
18	Misc Ancillary Trans Rev	D10S		191,454	66,730	124,724	7,127	117,597	87,114	22,559	7,618	305	0
19	MISO	D10S	456	1,649	575	1,074	61	1,013	750	194	66	3	0
20	Other	D10S	451,456,457	(74,738)	(26,049)	(48,689)	(2,782)	(45,906)	(34,007)	(8,806)	(2,974)	(119)	0
21	Late Pay Chg - Pres	R16C; R02		4,390	3,493	894	206	688	628	59	1	0	3
22	**Tot Other Op - Pres**		450	621,402	198,037	421,385	21,691	399,694	290,029	74,920	33,650	1,095	1,981
23	Incr Misc Serv - Prop	R01,		0	0	0	0	0	0	0	0	0	0
24	Incr Inter-Dept'l - Prop	R01; R02		16	6	10	1	9	7	2	1	0	0
25	Incr Late Pay - Prop	(R16C); R02		91	73	19	4	14	13	1	0	0	0
26	**Tot Other Op - Prop**			621,509	198,115	421,413	21,696	399,718	290,050	74,923	33,650	1,095	1,981
27	**Tot Oper Rev - Pres**			3,448,403	1,221,641	2,198,452	129,830	2,068,622	1,541,435	358,517	162,948	5,723	28,311
28	**Tot Oper Rev - Prop**			3,507,311	1,243,010	2,235,442	132,084	2,103,359	1,567,483	364,418	165,638	5,819	28,859
	Operating & Maint (Pg 1 of 2)												
	Production Expen												
29	**Fuel**	E8760	501,518,547	566,923	165,750	398,764	18,895	379,869	272,530	70,615	35,651	1,073	2,409
	Purchased Power												
30	Purchases: Cap Peak	D10S		109,750	38,253	71,497	4,085	67,412	49,938	12,932	4,367	175	0
31	Purchases: Cap Base	D10S		40,840	14,234	26,605	1,520	25,085	18,583	4,812	1,625	65	0
32	Purchases: Demand		555	150,590	52,487	98,103	5,606	92,497	68,520	17,744	5,992	240	0
33	Purchases: Other Energy	E8760	555	505,394	147,761	355,485	16,844	338,641	242,952	62,951	31,782	956	2,148
34	Tot Non-Assoc Purch			655,984	200,248	453,588	22,450	431,138	311,472	80,695	37,774	1,196	2,148
35	Interchg Agr Capacity	P10WoN	557	41,222	12,844	28,263	1,429	26,834	19,454	5,040	2,267	74	115
36	Interchg Agr Energy	E8760	557	18,558	5,426	13,053	619	12,435	8,921	2,312	1,167	35	79
37	Tot Wis Interchg Purch			59,780	18,270	41,316	2,047	39,269	28,375	7,351	3,434	109	194
38	**Tot Purchased Power**			715,764	218,518	494,904	24,497	470,407	339,847	88,047	41,208	1,305	2,342
	Other Production		500,502,505-507 509-514,517,519,520, 523-525,528-532,535, 539,543-546,548-550 552-554,556,557 575.1-575.8										
39	Capacity Related	D10S		162,853	56,761	106,092	6,062	100,030	74,101	19,189	6,480	260	0
40	Energy Related	E8760		337,459	98,662	237,362	11,247	226,115	162,222	42,033	21,221	639	1,434
41	Total Other Produc	32.55%		500,312	155,423	343,454	17,309	326,145	236,323	61,223	27,701	898	1,434
42	**Total Production**			1,782,999	539,691	1,237,122	60,701	1,176,421	848,700	219,884	104,560	3,276	6,186
43	**Transmission Exp**	D10S	560-563, 565-568 570-573	191,916	66,891	125,025	7,144	117,881	87,325	22,614	7,637	306	0

PUBLIC DOCUMENT
TRADE SECRET INFORMATION AND NON-PUBLIC DATA EXCISED

Operating & Maint (Pg 2 of 2)				1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
	Distribution Expen	Alloc	FERC Accounts	MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
1	Supervision & Eng'rg	ZDTS	580,590	7,480	4,152	3,028	375	2,654	2,157	364	131	2	300
2	Load Dispatching	T20D80	581	6,130	2,326	3,769	216	3,553	2,636	672	242	2	35
3	Substations	P61	582,591,592	8,616	3,240	5,325	293	5,032	3,550	900	582	0	51
4	Overhead Lines	POL	583,593	36,452	23,096	11,200	1,587	9,613	8,374	1,238	0	0	2,156
5	Underground Lines	PUL	584, 594	16,071	12,488	3,526	864	2,662	2,535	127	0	0	58
6	Line Transformers	P68	595	2,192	1,428	755	111	644	629	15	0	0	8
7	Meters	C12WM	586,597,598	3,279	2,226	1,047	358	690	620	63	5	1	6
8	Customer Install'n	OXDTS	587	3,453	2,059	1,170	157	1,013	839	137	36	0	225
9	Street Lighting	Dir Assign	585,596	2,611	0	0	0	0	0	0	0	0	2,611
10	Miscellaneous	OXDTS	588	13,968	8,328	4,731	635	4,096	3,393	555	147	1	909
11	Rents (Pole Attachmts)	POL	589	3,238	2,051	995	141	854	744	110	0	0	191
12	**Total Distribution**			103,490	61,393	35,546	4,736	30,810	25,477	4,181	1,144	7	6,551
13	**Customer Accounting**	C11WA	901-905	48,049	39,624	8,126	4,634	3,492	3,434	54	3	2	299
14	**Sales, Econ Dvlp & Other**	R01	912	101	37	64	4	60	45	10	5	0	1
	Admin & General												
15	Salaries	LABOR	920	44,771	16,530	27,875	1,765	26,110	19,186	4,773	2,085	67	365
16	Office Supplies	OXTS	921	42,250	14,145	27,839	1,540	26,299	19,163	4,873	2,192	71	266
17	Admin Transfer Credit	OXTS	922	(31,886)	(10,676)	(21,010)	(1,162)	(19,848)	(14,463)	(3,677)	(1,654)	(54)	(200)
18	Outside Services	LABOR	923	16,467	6,080	10,253	649	9,604	7,057	1,756	767	25	134
19	Property Insurance	NEPIS	924	6,472	2,663	3,761	249	3,512	2,610	626	268	8	48
20	Pensions & Benefits	LABOR	926	68,121	25,152	42,414	2,686	39,728	29,192	7,263	3,172	102	555
21	Injuries & Claims	LABOR	925	16,036	5,921	9,985	632	9,352	6,872	1,710	747	24	131
22	Regulatory Exp	R01; R02	928	3,430	1,242	2,156	131	2,025	1,518	344	157	6	32
23	General Advertising	OXTS	930.1	1,134	380	747	41	706	514	131	59	2	7
24	Contributions	OXTS		0	0	0	0	0	0	0	0	0	0
25	Misc General Exp	OXTS	929, 930.2	596	200	393	22	371	270	69	31	1	4
26	Rents	OXTS	931	22,979	7,693	15,141	838	14,304	10,423	2,650	1,192	39	144
27	Maint of General Plant	OXTS	935	371	124	245	14	231	168	43	19	1	2
28	Total			190,741	69,455	119,799	7,405	112,394	82,512	20,558	9,033	291	1,487
	Cust Service & Info												
29	Cust Assist Exp - Non-CIP	C11P10	908	2,022	1,195	803	104	699	515	125	57	2	25
30	CIP Total	E99XCIP	908	90,716	27,423	62,748	3,031	59,717	46,012	10,776	2,737	193	544
31	Instructional Advertising	C11P10	909	752	445	299	39	260	192	46	21	1	9
32	Total			93,490	29,063	63,849	3,173	60,676	46,719	10,946	2,816	195	578
33	Amortizations	LABOR		31,300	11,557	19,488	1,234	18,254	13,413	3,337	1,457	47	255
34	**Total O&M Expense**			2,442,086	817,709	1,609,019	89,032	1,519,987	1,107,625	281,585	126,654	4,123	15,357

	Book Depreciation			1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		65,489	22,826	42,663	2,438	40,225	29,798	7,717	2,606	104	0
2	Base Load	E8760		131,392	38,415	92,419	4,379	88,040	63,162	16,366	8,263	249	558
3	Total		403,413	196,881	61,240	135,082	6,817	128,265	92,961	24,083	10,869	353	558
	Transmission												
4	Gen Step Up Base	E8760		(18,946)	(5,539)	(13,327)	(631)	(12,695)	(9,108)	(2,360)	(1,191)	(36)	(81)
5	Gen Step Up Peak	D10S		(9,848)	(3,432)	(6,415)	(367)	(6,049)	(4,481)	(1,160)	(392)	(16)	0
6	Total Gen Step Up			(28,794)	(8,972)	(19,742)	(998)	(18,744)	(13,589)	(3,520)	(1,583)	(52)	(81)
7	Bulk Transmission	D10S		2,199	766	1,432	82	1,350	1,000	259	87	4	0
8	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
9	Direct Assign	Dir Assign		170	0	170	0	170	3	0	166	0	0
10	Total		403,413	(26,426)	(8,205)	(18,140)	(916)	(17,224)	(12,585)	(3,261)	(1,330)	(48)	(81)
	Distribution												
11	Generat Step Up	STRATH		90	27	62	3	59	43	11	5	0	0
12	Bulk Transmission	D10S		49	17	32	2	30	22	6	2	0	0
13	Distrib Function	D60Sub		11,264	4,382	6,812	395	6,417	4,781	1,213	422	0	69
14	Direct Assign	Dir Assign		591	0	591	0	591	12	0	579	0	0
15	Total Substations		403,413	11,993	4,426	7,497	400	7,097	4,858	1,230	1,008	0	70
16	Overhead Lines	POL		5,313	3,366	1,632	231	1,401	1,220	180	0	0	314
17	Underground	PUL		14,065	10,929	3,086	756	2,330	2,219	111	0	0	50
18	Line Transformers	P68		2,663	1,735	917	135	782	764	18	0	0	10
19	Services	P69		2,430	2,147	283	81	202	202	0	0	0	0
20	Meters	C12WM		1,374	932	439	150	289	260	26	2	1	3
21	Street Lighting	P73		2,199	0	0	0	0	0	0	0	0	2,199
22	Total		403,413	40,036	23,536	13,855	1,754	12,101	9,524	1,566	1,010	1	2,646
23	**General Plant**	PTD	403,413	62,817	24,706	37,500	2,368	35,132	25,954	6,305	2,788	86	611
24	**Electric Common**	PTD	403,413	0	0	0	0	0	0	0	0	0	0
25	**Total Book Deprec**		403,404	273,308	101,277	168,297	10,022	158,274	115,853	28,692	13,337	391	3,734
	Real Estate & Property Tax												
	Production												
26	Peaking Plant	D10S		27,893	9,722	18,171	1,038	17,133	12,692	3,287	1,110	44	0
27	Base Load	E8760		53,664	15,690	37,746	1,789	35,958	25,797	6,684	3,375	102	228
28	Total		408.1	81,557	25,411	55,917	2,827	53,090	38,489	9,971	4,485	146	228
	Transmission												
29	Gen Step Up Base	E8760		575	168	404	19	385	276	72	36	1	2
30	Gen Step Up Peak	D10S		299	104	195	11	184	136	35	12	0	0
31	Total Gen Step Up			874	272	599	30	569	412	107	48	2	2
32	Bulk Transmission	D10S		26,748	9,323	17,425	996	16,430	12,171	3,152	1,064	43	0
33	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
34	Direct Assign	Dir Assign		102	0	102	0	102	2	0	100	0	0
35	Total		408.1	27,724	9,595	18,126	1,026	17,100	12,585	3,259	1,212	44	2
	Distribution												
36	Generat Step Up	STRATH		46	14	32	2	31	22	6	3	0	0
37	Bulk Transmission	D10S		24	8	16	1	15	11	3	1	0	0
38	Distrib Function	D60Sub		7,640	2,972	4,621	268	4,353	3,243	823	286	0	47
39	Direct Assign	Dir Assign		253	0	253	0	253	5	0	248	0	0
40	Total Substations			7,963	2,995	4,921	271	4,651	3,281	832	538	0	47
41	Overhead Lines	POL		9,570	6,063	2,940	417	2,524	2,199	325	0	0	566
42	Underground	PUL		16,376	12,725	3,593	880	2,713	2,583	129	0	0	59
43	Line Transformers	P68		5,444	3,548	1,875	276	1,599	1,563	37	0	0	21
44	Services	P69		3,476	3,071	405	116	289	289	0	0	0	0
45	Meters	C12WM		1,433	972	458	156	301	271	27	2	1	3
46	Street Lighting	P73		811	0	0	0	0	0	0	0	0	811
47	Total		408.1	45,074	29,374	14,192	2,116	12,076	10,186	1,350	540	1	1,507
48	**General & Common Plant**	PTD	408.1	0	0	0	0	0	0	0	0	0	0
49	**Tot Rl Est & Pr Tax**			154,354	64,381	88,236	5,969	82,267	61,260	14,579	6,237	191	1,738
50	Gross Earnings Tax	R01; R02		0	0	0	0	0	0	0	0	0	0
51	Payroll Taxes	LABOR		29,409	10,859	18,311	1,159	17,151	12,603	3,135	1,369	44	240
52	**Tot Non-Inc Taxes**			183,763	75,239	106,547	7,128	99,418	73,862	17,715	7,606	235	1,977

	Provision For Defer Inc Tax			1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
	Production	Alloc	FERC Accounts	MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
1	Peaking Plant	D10S		3,643	1,270	2,373	136	2,237	1,657	429	145	6	0
2	Nuclear Fuel	E8760		(17,104)	(5,001)	(12,031)	(570)	(11,461)	(8,222)	(2,130)	(1,076)	(32)	(73)
3	Base Load	E8760		(3,680)	(1,076)	(2,589)	(123)	(2,466)	(1,769)	(458)	(231)	(7)	(16)
4	Total		410, 411	(17,142)	(4,807)	(12,247)	(557)	(11,689)	(8,334)	(2,160)	(1,162)	(34)	(88)
	Transmission												
5	Gen Step Up Base	E8760		7,844	2,293	5,517	261	5,256	3,771	977	493	15	33
6	Gen Step Up Peak	D10S		4,077	1,421	2,656	152	2,504	1,855	480	162	7	0
7	Total Gen Step Up			11,921	3,714	8,173	413	7,760	5,626	1,457	656	21	33
8	Bulk Transmission	D10S		50,635	17,648	32,987	1,885	31,102	23,040	5,966	2,015	81	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		204	0	204	0	204	4	0	200	0	0
11	Total		410, 411	62,761	21,363	41,364	2,298	39,066	28,670	7,424	2,871	102	33
	Distribution												
12	Generat Step Up	STRATH		(36)	(11)	(25)	(1)	(24)	(17)	(4)	(2)	(0)	(0)
13	Bulk Transmission	D10S		(2)	(1)	(1)	(0)	(1)	(1)	(0)	(0)	(0)	0
14	Distrib Function	D60Sub		4,462	1,736	2,699	157	2,542	1,894	481	167	0	27
15	Direct Assign	Dir Assign		(75)	0	(75)	0	(75)	(2)	0	(74)	0	0
16	Total Substations			4,349	1,724	2,597	155	2,442	1,875	476	91	(0)	27
17	Overhead Lines	POL		11,307	7,164	3,474	492	2,982	2,598	384	0	0	669
18	Underground	PUL		12,427	9,656	2,726	668	2,058	1,960	98	0	0	45
19	Line Transformers	P68		2,376	1,549	819	120	698	682	16	0	0	9
20	Services	P69		872	771	102	29	72	72	0	0	0	0
21	Meters	C12WM		867	588	277	95	182	164	17	1	0	2
22	Street Lighting	P73		244	0	0	0	0	0	0	0	0	244
23	Total		410, 411	32,442	21,452	9,995	1,560	8,435	7,351	991	93	0	995
24	**General & Common Plant**	PTD	410, 411	5,472	2,152	3,267	206	3,061	2,261	549	243	7	53
25	**Net Operating Loss (NOL) Carr**	NEPIS		80,536	33,133	46,806	3,104	43,702	32,477	7,788	3,335	103	597
26	**Non - Plant Related**	LABOR	410, 411	0	0	0	0	0	0	0	0	0	0
27	**Tot Prov For Defer**			164,068	73,292	89,185	6,611	82,574	62,424	14,592	5,379	179	1,591
	Inv Tax Credit; Total Oper Exp												
	Production												
28	Peaking Plant	D10S		(299)	(104)	(195)	(11)	(184)	(136)	(35)	(12)	(0)	0
29	Base Load	E8760		(568)	(166)	(400)	(19)	(381)	(273)	(71)	(36)	(1)	(2)
30	Total		411	(867)	(270)	(594)	(30)	(564)	(409)	(106)	(48)	(2)	(2)
	Transmission												
31	Bulk Transmission	D10S		(477)	(166)	(311)	(18)	(293)	(217)	(56)	(19)	(1)	0
32	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
33	Total		411	(477)	(166)	(311)	(18)	(293)	(217)	(56)	(19)	(1)	0
	Distribution												
34	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
35	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
36	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
37	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
38	Total Substations			0	0	0	0	0	0	0	0	0	0
39	Overhead Lines	POL		(746)	(473)	(229)	(33)	(197)	(171)	(25)	0	0	(44)
40	Underground	PUL		0	0	0	0	0	0	0	0	0	0
41	Line Transformers	P68		0	0	0	0	0	0	0	0	0	0
42	Services	P69		0	0	0	0	0	0	0	0	0	0
43	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
44	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
45	Total		411	(746)	(473)	(229)	(33)	(197)	(171)	(25)	0	0	(44)
46	**General & Common Plant**	PTD	411	(9)	(4)	(6)	(0)	(5)	(4)	(1)	(0)	(0)	(0)
47	**Electric Common**	PTD	411	0	0	0	0	0	0	0	0	0	0
25	**Tot ITC For Curr Inc**			(2,100)	(913)	(1,140)	(81)	(1,059)	(802)	(189)	(67)	(2)	(47)
26	**Gross Inv Tax Credit**			0									
47	**Net Inv Tax Credit**			(2,100)	(913)	(1,140)	(81)	(1,059)	(802)	(189)	(67)	(2)	(47)
28	TBT Misc Net Exp	NEPIS		0	0	0	0	0	0	0	0	0	0
48	**Total Operating Exp**			**3,061,125**	**1,066,605**	**1,971,908**	**112,712**	**1,859,195**	**1,358,963**	**342,396**	**152,910**	**4,927**	**22,612**
49A	**Pres Op Inc Before Inc Tax**			**387,278**	**155,035**	**226,544**	**17,117**	**209,427**	**182,472**	**16,121**	**10,038**	**796**	**5,698**
49B	**Prop Op Inc Before Inc Tax**			**446,185**	**176,404**	**263,535**	**19,371**	**244,163**	**208,520**	**22,022**	**12,728**	**893**	**6,246**

Tax Deprec; Inc Tax & Return

				1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		91,528	31,901	59,626	3,407	56,219	41,646	10,785	3,642	146	0
2	Nuclear Fuel	E8760		73,085	21,368	51,407	2,436	48,971	35,133	9,103	4,596	138	311
3	Base Load	E8760		196,582	57,474	138,272	6,552	131,720	94,500	24,486	12,362	372	835
4	Total		tax books	361,195	110,743	249,305	12,395	236,911	171,280	44,374	20,600	656	1,146
	Transmission												
5	Gen Step Up Base	E8760		913	267	642	30	612	439	114	57	2	4
6	Gen Step Up Peak	D10S		474	165	309	18	291	216	56	19	1	0
7	Total Gen Step Up			1,387	432	951	48	903	655	170	76	2	4
8	Bulk Transmission	D10S		129,328	45,076	84,251	4,814	79,437	58,846	15,239	5,146	206	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		681	0	681	0	681	14	0	668	0	0
11	Total		tax books	131,396	45,508	85,884	4,862	81,022	59,514	15,408	5,890	209	4
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		35	12	23	1	22	16	4	1	0	0
14	Distrib Function	D60Sub		22,241	8,653	13,451	781	12,671	9,441	2,396	833	0	137
15	Direct Assign	Dir Assign		324	0	324	0	324	6	0	318	0	0
16	Total Substations			22,600	8,665	13,798	782	13,016	9,464	2,400	1,152	0	137
17	Overhead Lines	POL		33,354	21,133	10,248	1,453	8,796	7,663	1,133	0	0	1,973
18	Underground	PUL		44,435	34,527	9,749	2,388	7,360	7,010	350	0	0	159
19	Line Transformers	P68		8,537	5,563	2,941	433	2,508	2,451	57	0	0	33
20	Services	P69		4,842	4,278	564	162	402	402	0	0	0	0
21	Meters	C12WM		3,632	2,465	1,160	396	764	687	70	6	2	7
22	Street Lighting	P73		2,786	0	0	0	0	0	0	0	0	2,786
23	Total		tax books	120,186	76,631	38,460	5,614	32,846	27,676	4,011	1,158	2	5,095
24	**General & Common Plant**	PTD	tax books	61,760	24,291	36,869	2,328	34,541	25,517	6,199	2,741	84	600
25	**Electric Common**	PTD	tax books	0	0	0	0	0	0	0	0	0	0
25	Net Operating Loss (NOL) Carry	NEPIS		242,473	99,754	140,920	9,345	131,576	97,779	23,447	10,040	310	1,799
26	**Total Tax Deprec**			917,010	356,927	551,439	34,543	516,895	381,766	93,439	40,430	1,261	8,644
27	Interest Expense		427,431	145,458	58,305	86,029	5,536	80,493	59,626	14,440	6,234	193	1,124
28	Other Tax Timing Differ	LABOR		21,620	7,983	13,461	852	12,609	9,265	2,305	1,007	32	176
29	Total Tax Deductions			1,084,088	423,215	650,929	40,932	609,997	450,657	110,184	47,671	1,486	9,944
	Inc Tax Additions												
30	Book Depreciation			273,308	101,277	168,297	10,022	158,274	115,853	28,692	13,337	391	3,734
31	Deferred Inc Tax & ITC			161,968	72,379	88,045	6,530	81,515	61,623	14,403	5,312	177	1,544
32	Nuclear Fuel Book Burn	E8760		119,366	34,899	83,960	3,978	79,981	57,381	14,868	7,506	226	507
34	Nuclear Fuel Disposal	E8760		0	0	0	0	0	0	0	0	0	0
33	Tax Capitalized Leases	PTD		78,224	30,766	46,698	2,948	43,749	32,320	7,852	3,472	107	760
34	Meals & Entertainment	LABOR		(740)	(273)	(461)	(29)	(432)	(317)	(79)	(34)	(1)	(6)
35	Avoided Tax Interest	RTBASE		17,455	6,997	10,324	664	9,659	7,155	1,733	748	23	135
36	Total Tax Additions			649,581	246,045	396,862	24,114	372,747	274,015	67,469	30,341	923	6,675
37	**Total Inc Tax Adjustments**			(434,506)	(177,170)	(254,067)	(16,817)	(237,250)	(176,642)	(42,715)	(17,330)	(563)	(3,269)
38A	**Pres Taxable Net Income**			(47,229)	(22,135)	(27,523)	300	(27,823)	5,830	(26,594)	(7,292)	233	2,429
38B	**Prop Taxable Net Income**			11,679	(766)	9,468	2,554	6,914	31,879	(20,693)	(4,602)	330	2,977
39A	Pres Fed & State Inc Tax			(19,954)	(9,324)	(11,632)	108	(11,740)	2,241	(11,043)	(3,034)	96	1,002
39B	Prop Fed & State Inc Tax			4,416	(483)	3,671	1,041	2,630	13,018	(8,602)	(1,922)	136	1,228
40A	Pres Preliminary Return	(total); BASE		407,232	164,359	238,176	17,009	221,167	180,230	27,164	13,073	700	4,697
40B	Prop Preliminary Return	(total); BASE		441,769	176,888	259,864	18,331	241,533	195,503	30,624	14,650	757	5,018
41	Total AFUDC			34,864	11,875	22,829	1,244	21,584	15,744	4,006	1,778	56	160
42A	**Present Total Return**			442,096	176,234	261,005	18,253	242,752	195,974	31,170	14,851	756	4,857
42B	**Proposed Total Return**			476,634	188,763	282,693	19,575	263,118	211,247	34,630	16,428	813	5,178
43A	**Pres % Return on Rate Base**			0	6.77%	6.80%	7.39%	6.76%	7.36%	4.84%	5.34%	8.78%	9.68%
43B	**Prop % Return on Rate Base**			0	7.25%	7.36%	7.92%	7.32%	7.94%	5.37%	5.90%	9.44%	10.32%
44A	**Present Common Return**			296,639	117,930	174,976	12,718	162,258	136,348	16,730	8,616	564	3,733
44B	**Proposed Common Return**			331,176	130,458	196,664	14,039	182,624	151,621	20,190	10,194	620	4,054
45A	**Pres % Ret on Common Rt Base**			0	8.63%	8.68%	9.80%	8.60%	9.76%	4.94%	5.90%	12.47%	14.17%
45B	**Prop % Ret on Common Rt Base**			0	9.55%	9.75%	10.82%	9.68%	10.85%	5.97%	6.98%	13.71%	15.39%

Allow For Funds Used During Constr

				1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		3,414	1,190	2,224	127	2,097	1,554	402	136	5	0
2	Nuclear Fuel	E8760		4,875	1,425	3,429	162	3,267	2,344	607	307	9	21
3	Base Load	E8760		13,381	3,912	9,412	446	8,966	6,433	1,667	841	25	57
4	Total		419.1,432	21,671	6,528	15,066	736	14,330	10,330	2,676	1,284	40	78
	Transmission												
5	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10S		0	0	0	0	0	0	0	0	0	0
7	Total Gen Step Up			0	0	0	0	0	0	0	0	0	0
8	Bulk Transmission	D10S		6,380	2,224	4,157	238	3,919	2,903	752	254	10	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		3	0	3	0	3	0	0	3	0	0
11	Total		419.1,432	6,383	2,224	4,159	238	3,922	2,903	752	257	10	0
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub		1,108	431	670	39	631	470	119	42	0	7
15	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
16	Total Substations			1,108	431	670	39	631	470	119	42	0	7
17	Overhead Lines	POL		213	135	66	9	56	49	7	0	0	13
18	Underground	PUL		1,052	818	231	57	174	166	8	0	0	4
19	Line Transformers	P68		4	2	1	0	1	1	0	0	0	0
20	Services	P69		1	1	0	0	0	0	0	0	0	0
21	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73		17	0	0	0	0	0	0	0	0	17
23	Total		419.1,432	2,394	1,387	968	105	863	686	135	42	0	40
24	**General & Common Plant**	PTD	419.1,432	4,416	1,737	2,636	166	2,470	1,824	443	196	6	43
25	**Total AFUDC**			34,864	11,875	22,829	1,244	21,584	15,744	4,006	1,778	56	160

Labor Allocator

	Production												
26	Other Prod - Cap	D10S		83,408	29,071	54,337	3,105	51,232	37,952	9,828	3,319	133	0
27	Other Prod - Ene	E8760		160,470	46,916	112,872	5,348	107,524	77,141	19,988	10,091	304	682
28	Total		500 through 557	243,878	75,988	167,209	8,453	158,756	115,093	29,816	13,410	437	682
	Transmission												
29	Stepup Subtrans	P5161A		601	187	412	21	392	284	74	33	1	2
30	Bulk Power Subs	D10S		18,400	6,413	11,987	685	11,302	8,372	2,168	732	29	0
31	Total		560 through 571	19,001	6,600	12,399	706	11,694	8,656	2,242	765	30	2
	Distribution												
32	Superv & Eng	ZDTS	580, 590	5,816	3,228	2,355	291	2,064	1,677	283	102	2	233
33	Load Dispatch	D10S	581	5,310	1,851	3,459	198	3,261	2,416	626	211	8	0
34	Substation	P61	582, 592	5,527	2,078	3,415	188	3,228	2,277	577	373	0	33
35	Overhead Lines	POL	583, 593	6,809	4,314	2,092	297	1,796	1,564	231	0	0	403
36	Underground Lines	PUL	584, 594	2,156	1,675	473	116	357	340	17	0	0	8
37	Line Transformer	P68	595	6,611	4,308	2,277	335	1,942	1,898	44	0	0	25
38	Meter	C12WM	586, 597	4,224	2,867	1,349	461	888	799	81	7	2	8
39	Cust Installation	ZDTS	587	2,917	1,619	1,181	146	1,035	841	142	51	1	117
40	Street Lighting	P73	585, 596	620	0	0	0	0	0	0	0	0	620
41	Miscellaneous	OXDTS	588	6,210	3,702	2,103	282	1,821	1,508	247	66	0	404
42	Total			46,199	25,643	18,705	2,313	16,392	13,320	2,248	810	13	1,851
43	**Cust Accounting**	C11WA	901,902,903,904,905	12,198	10,059	2,063	1,176	886	872	14	1	0	76
44	**Sales Expense**	C11P10	912	6	3	2	0	2	1	0	0	0	0
45	**Admin & General**	LABOR	920,921,922,923,924,	120,936	44,653	75,298	4,768	70,530	51,826	12,893	5,631	181	985
46	**Service & Inform**	C11P10	908, 909	1,500	886	595	77	518	382	92	43	1	18
47	**Labor**			443,718	163,832	276,272	17,494	258,778	190,150	47,306	20,660	663	3,614

			1=2+3+10	2	3=4+5	4	5	6	7	8	9	
INTERNAL ALLOCATORS		Intern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	50% Cus, 50% Prod Plt	C11P10	100.00%	59.09%	39.69%	5.13%	34.57%	25.47%	6.16%	2.84%	0.09%	1.21%
2	Peaking Plant Capacity	D10S	100.00%	34.85%	65.15%	3.72%	61.42%	45.50%	11.78%	3.98%	0.16%	0.00%
3	57% Dmd; 43% Energy: Sales &	D57E43	100.00%	32.64%	67.19%	3.57%	63.62%	46.51%	12.05%	4.89%	0.17%	0.17%
4	40% Dmd; 60% Energy: CIP	D40E60	100.00%	31.52%	68.23%	3.49%	64.73%	47.03%	12.18%	5.35%	0.18%	0.25%
5	20%D10T; 80%D60Sub	T20D80	100.00%	37.94%	61.48%	3.53%	57.95%	43.00%	10.97%	3.95%	0.03%	0.57%
6	Labor w/o (or w/) A&G	LABOR	100.00%	36.92%	62.26%	3.94%	58.32%	42.85%	10.66%	4.66%	0.15%	0.81%
7	Net Plant In Service	NEPIS	100.00%	41.14%	58.12%	3.85%	54.26%	40.33%	9.67%	4.14%	0.13%	0.74%
8	Dis O&M w/o Sup & Misc	OXDTS	100.00%	59.62%	33.87%	4.54%	29.33%	24.29%	3.98%	1.06%	0.00%	6.51%
9	O&M w/o Reg Ex & OXTS-Alloc'	OXTS	100.00%	33.48%	65.89%	3.65%	62.25%	45.36%	11.53%	5.19%	0.17%	0.63%
10	Production Plant	P10	100.00%	30.71%	68.98%	3.43%	65.55%	47.40%	12.28%	5.68%	0.18%	0.31%
11	Production Plant Wo Nuclear	P10WoN	100.00%	31.16%	68.56%	3.47%	65.10%	47.19%	12.23%	5.50%	0.18%	0.28%
12	Total P51 & P61A	P5161A	100.00%	31.11%	68.61%	3.46%	65.15%	47.22%	12.23%	5.52%	0.18%	0.28%
13	Distribution Plant	P60	100.00%	65.17%	31.49%	4.69%	26.79%	22.60%	3.00%	1.20%	0.00%	3.34%
14	Distr Substn Plant	P61	100.00%	37.61%	61.80%	3.40%	58.40%	41.21%	10.44%	6.75%	0.00%	0.59%
15	Line Transformer Plant	P68	100.00%	65.17%	34.45%	5.07%	29.38%	28.71%	0.67%	0.00%	0.00%	0.39%
16	Services Plant	P69	100.00%	88.35%	11.65%	3.34%	8.30%	8.30%	0.00%	0.00%	0.00%	0.00%
17	Dist Plt Overhead Lines	POL	100.00%	63.36%	30.73%	4.35%	26.37%	22.97%	3.40%	0.00%	0.00%	5.91%
18	Real Est & Property Tax	PT0	100.00%	41.71%	57.16%	3.87%	53.30%	39.69%	9.45%	4.04%	0.12%	1.13%
19	Produc, Trans & Distrib	PTD	100.00%	39.33%	59.70%	3.77%	55.93%	41.32%	10.04%	4.44%	0.14%	0.97%
20	Dist Plt Undground Lines	PUL	100.00%	77.70%	21.94%	5.37%	16.56%	15.78%	0.79%	0.00%	0.00%	0.36%
21	Rate Base (Non-Column)	RTBASE	100.00%	40.08%	59.14%	3.81%	55.34%	40.99%	9.93%	4.29%	0.13%	0.77%
22	Stratified Hydro Baseload	STRATH	100.00%	30.03%	69.60%	3.39%	66.22%	47.71%	12.36%	5.96%	0.19%	0.36%
23	Transmission & Distrib	TD	100.00%	53.00%	44.99%	4.30%	40.69%	31.68%	6.48%	2.46%	0.06%	2.02%
24	Labor Dis w/o Sup & Eng	ZDTS	100.00%	55.50%	40.49%	5.01%	35.48%	28.83%	4.87%	1.75%	0.03%	4.01%

			1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
INTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
25	Labor w/o A&G	LABOR(S)	322,782	119,179	200,974	12,726	188,248	138,325	34,413	15,029	482	2,629
26	Dis O&M w/o Sup, Cust Install &	OXDTS	78,588	46,855	26,617	3,570	23,047	19,089	3,125	829	4	5,117
27	O&M w/o Reg Ex & OXTS-Alloc'	OXTS	2,403,212	804,601	1,583,509	87,608	1,495,900	1,090,030	277,154	124,659	4,058	15,102
28	Total P51 & P61A	P5161A	66,121	20,567	45,366	2,289	43,077	31,220	8,088	3,650	119	188
29	Produc, Trans & Distrib	PTD	12,972,204	5,102,058	7,744,037	488,938	7,255,098	5,359,672	1,302,054	575,704	17,668	126,110
30	Transmission & Distrib	TD	5,019,617	2,660,164	2,258,305	215,788	2,042,516	1,590,171	325,480	123,626	3,239	101,149
31	Labor Dis w/o Sup & Eng, Cust I	ZDTS	37,466	20,795	15,169	1,876	13,293	10,802	1,823	657	11	1,501

			1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
EXTERNAL ALLOCATORS		Extern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Customers - Ave Monthly	C11	100.00%	87.48%	10.41%	6.82%	3.59%	3.55%	0.04%	0.00%	0.00%	2.11%
2	Cust Acctg Wtg Factor	C11WA	100.00%	82.46%	16.91%	9.64%	7.27%	7.15%	0.11%	0.01%	0.00%	0.62%
3	Mo Cus Wtd By Mtr Invest	C12WM	100.00%	67.87%	31.94%	10.91%	21.03%	18.91%	1.92%	0.16%	0.04%	0.19%
4	Sec & Pri Customers	C61PS	100.00%	89.06%	10.61%	6.95%	3.66%	3.62%	0.04%	0.00%	0.00%	0.33%
5	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	100.00%	95.21%	4.54%	3.91%	0.63%	0.62%	0.00%	0.00%	0.00%	0.25%
6	C62Sec, w/o Ltg & C/I Undergrc	C62NL	100.00%	94.41%	5.59%	3.67%	1.91%	1.91%	0.00%	0.00%	0.00%	0.00%
7	Secondary Customers	C62Sec	100.00%	89.10%	10.57%	6.95%	3.62%	3.62%	0.00%	0.00%	0.00%	0.33%
8	Summer Peak Resp KW	D10S	100.00%	34.85%	65.15%	3.72%	61.42%	45.50%	11.78%	3.98%	0.16%	0.00%
9	Transmission Demand %	D10T	100.00%	34.09%	65.50%	3.60%	61.90%	45.21%	11.74%	4.77%	0.17%	0.41%
10	Winter Peak Resp KW	D10W	100.00%	33.05%	65.97%	3.43%	62.54%	44.81%	11.68%	5.85%	0.19%	0.98%
11	Alternative Production Allocator	1CP	100.00%	34.85%	65.15%	3.72%	61.42%	45.50%	11.78%	3.98%	0.16%	0.00%
12	Sec, Pri & TT, Class Coin kW @	D60Sub	100.00%	38.91%	60.48%	3.51%	56.97%	42.45%	10.77%	3.75%	0.00%	0.62%
13	Sec & Pri, Cl Coin kW (no Min Sy	D61PS	100.00%	35.16%	64.34%	3.09%	61.26%	48.75%	12.51%	0.00%	0.00%	0.50%
14	Pri & Sec Coin kW Served w/ 1 F	D61PS1Ph	100.00%	76.44%	22.80%	3.53%	19.27%	17.08%	2.19%	0.00%	0.00%	0.76%
15	D62Sec, w/o Ltg & C/I Undergrc	D62NLL	100.00%	72.25%	27.75%	2.47%	25.28%	25.28%	0.00%	0.00%	0.00%	0.00%
16	Sec, Class Coin kW (w/o Min Sy	D62SecL	100.00%	48.26%	51.32%	3.70%	47.62%	47.62%	0.00%	0.00%	0.00%	0.42%
17	Direct Assign Street Lighting	DASL	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
18	On + Off Sales MWH	E8760	100.00%	29.24%	70.34%	3.33%	67.01%	48.07%	12.46%	6.29%	0.19%	0.43%
19	Street Lighting (Dir Assign)	P73	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
20	MWh Sales Excl CIP Exempt	E99XCIP	100.00%	30.230%	69.17%	3.34%	65.829%	50.72%	11.88%	3.02%	0.21%	0.60%
21	Present Rev	R01	100.00%	36.21%	62.86%	3.83%	59.04%	44.27%	10.03%	4.57%	0.16%	0.93%
22	Rate Discount Allocator	DiscAlloc	100.00%	34.88%	65.10%	3.72%	61.38%	45.48%	11.75%	3.99%	0.16%	0.02%

			1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
EXTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
23	Customers - B Basis	C10	1,246,729	1,110,368	132,278	86,636	45,642	45,146	469	17	10	4,082
24	Cust - Ave Monthly (C10-Area Lt	C11	1,272,915	1,113,587	132,467	86,824	45,642	45,146	469	17	10	26,861
25	Mo Cus Wtd By Cus Acct	C11WA	1,348,405	1,111,962	228,042	130,047	97,994	96,363	1,513	76	43	8,401
26	Cust Acctg Wtg Factor	C11WAF	16.53	1.00	15.53	1.50	14.03	2.13	3.23	4.33	4.33	N/A
27	Cust-Ave Mo (C11 w/ Dir Assign	C12	1,247,752	1,113,587	132,467	86,824	45,642	45,146	469	17	10	1,698
28	Mo Cus Wtd By Mtr Invest	C12WM	139,013,836	94,348,476	44,403,548	15,171,232	29,232,317	26,286,769	2,663,081	222,840	59,626	261,811
29	Meter Invest / Cust Factor	C12WMF	25,496	85	25,257	175	25,082	582	5,683	12,749	6,067	154
30	Sec & Pri Customers	C61PS	1,246,702	1,110,368	132,251	86,636	45,615	45,146	469	0	0	4,082
31	% Served by Primary Single Phase		0.0%	74.5%	0.0%	39.2%	0.0%	12.0%	6.0%	0.0%	0.0%	52.3%
32	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	868,249	826,678	39,436	33,989	5,446	5,418	28	0	0	2,136
33	C62Sec, w/o Ltg & C/I Undergrc	C62NL	1,176,054	1,110,368	65,686	43,183	22,503	22,503	0	0	0	0
34	Secondary Customers	C62Sec	1,246,233	1,110,368	131,782	86,636	45,146	45,146	0	0	0	4,082
35	Summer Peak Resp KW	D10S	7,228	2,519	4,709	269	4,440	3,289	852	288	12	0
36	Dmd (D10S x Fact + D10W)/100	D10T	10,000,000	3,408,887	6,549,694	360,008	6,189,685	4,520,889	1,174,142	477,214	17,440	41,419
37	Winter Peak Resp KW	D10W	4,377	1,447	2,888	150	2,737	1,961	511	256	9	43
38	Alternative Production Allocator	1CP	7,228	2,519	4,709	269	4,440	3,289	852	288	12	0
39	Sec, Pri & TT, Class Coin kW @	D60Sub	7,906,068	3,075,858	4,781,578	277,549	4,504,029	3,356,061	851,693	296,275	0	48,632
40	Sec & Pri, Class Coin kW (w/o M	D61PS	6,789,272	2,387,380	4,368,238	209,462	4,158,776	3,309,455	849,320	0	0	33,654
41	Pri & Sec Coin kW Served w/ 1 F	D61PS1Ph	2,325,277	1,777,423	530,245	82,177	448,068	397,179	50,889	0	0	17,610
42	D62Sec, w/o Ltg & C/I Undergrc	D62NLL	9,292,559	6,713,761	2,578,797	229,922	2,348,875	2,348,875	0	0	0	0
43	Sec, Class Coin kW (w/o Min Sy	D62SecL	10,000,000	4,825,623	5,132,146	369,797	4,762,349	4,762,349	0	0	0	42,230
44	Annual Billing kW	D99	53,267.029	0	53,267	0	53,267	40,424	8,518	4,077	248	0
45	Summer Billing kW	D99S	19,423.061	0	19,423	0	19,423	14,775	3,164	1,392	91	0
46	Winter Billing kW	D99W	33,843.967	0	33,844	0	33,844	25,648	5,354	2,685	157	0
47	Non-Coinc Pk Second	DN-Sec	11,920,622	6,713,761	5,173,718	461,282	4,712,436	4,712,436	0	0	0	33,143
48	MWh Sales	E99	30,758,208	8,756,626	21,827,703	968,021	20,859,682	14,754,374	3,932,785	2,111,112	61,411	173,879
49	MWh Sales Excl CIP Exempt	E99XCIP	28,966,877	8,756,626	20,036,388	967,847	19,068,541	14,692,304	3,440,811	873,910	61,516	173,864

Summary of 2015 Compliance Class Cost of Service Study Results ($000) | Attachment B - Page 1 of 15

UNADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[1]	Unadjusted Rate Revenue Reqt (CCOSS page 2, line 1)	2,994,440	1,087,755	111,792	1,769,064	25,829
[2]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	306	224	14	67	1
[3]	Unadjusted Operating Revenues (line 1 + line 2)	2,994,746	1,087,979	111,806	1,769,131	25,830
[4]	Present Rates (CCOSS page 2, line 2)	2,826,661	1,023,121	108,086	1,669,134	26,319
[5]	Unadjusted Deficiency (line 3 - line 4)	168,085	64,857	3,720	99,997	(490)
[6]	Defic / Pres (line 5 / line 4)	5.9%	6.3%	3.4%	6.0%	-1.9%
[7]	**Ratio: Class % / Total %**	**1.00**	**1.07**	**0.58**	**1.01**	**-0.31**

COST RESPONSIBILITIES FOR RATE DISCOUNTS

		Total	Residential	Non-Demand	Demand	Street Ltg
		[TRADE SECRET BEGINS				
[8]	Rate Discounts (CCOSS page 2, line 5)					
[9]	Rate Discount Cost Allocation (CCOSS page 2, line 6)					
						TRADE SECRET ENDS]
[10]	Revenue Requirement Change (line 9 - line 8)	0	(614)	1,811	(1,209)	13

ADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[11]	Adjusted Rate Revenue Reqt (line 1 + line 10)	2,994,440	1,087,141	113,603	1,767,855	25,841
[12]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	306	224	14	67	1
[13]	Adjusted Operating Revenues (line 11 + line 12)	2,994,746	1,087,364	113,617	1,767,923	25,842
[14]	Present Rates (line 4)	2,826,661	1,023,121	108,086	1,669,134	26,319
[15]	Adjusted Deficiency (line 13 - line 14)	168,085	64,243	5,530	98,789	(477)
[16]	Defic / Pres Rates (line 15 / line 14)	5.9%	6.3%	5.1%	5.9%	-1.8%
[17]	**Ratio: Class % / Total %**	**1.00**	**1.06**	**0.86**	**1.00**	**-0.30**

	Rate Base		1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
	Plant In Service	Alloc	MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
1	Production		8,599,911	2,636,898	5,935,735	295,123	5,640,612	4,078,051	1,056,515	490,422	15,623	27,277
2	Transmission		2,080,982	720,352	1,360,449	77,024	1,283,425	944,767	244,623	90,715	3,319	181
3	Distribution		3,029,267	1,960,844	967,298	141,469	825,829	692,076	95,630	38,073	49	101,125
4	General		970,067	376,284	584,685	36,341	548,344	404,359	98,829	43,812	1,344	9,098
5	Common		0	0	0	0	0	0	0	0	0	0
6	Total Plant In Service		14,680,227	5,694,379	8,848,167	549,957	8,298,210	6,119,254	1,495,597	663,023	20,336	137,681
7	Production		4,507,780	1,372,539	3,120,215	154,025	2,966,189	2,141,983	554,943	261,023	8,240	15,027
8	Transmission		516,077	178,950	337,111	19,120	317,991	234,042	60,598	22,530	821	17
9	Distribution		1,105,502	704,458	341,198	50,747	290,450	242,383	33,335	14,711	21	59,846
10	General		424,327	164,594	255,753	15,896	239,857	176,875	43,230	19,164	588	3,980
11	Common		0	0	0	0	0	0	0	0	0	0
12	Total Depreciation Reserve		6,553,686	2,420,541	4,054,276	239,789	3,814,487	2,795,284	692,105	317,428	9,669	78,869
13	**Net Plant In Service**		8,126,541	3,273,838	4,793,891	310,168	4,483,723	3,323,970	803,492	345,594	10,666	58,812
14	Deducts: Accum Defer Inc Tax		1,731,010	718,738	1,003,502	67,220	936,283	696,549	166,200	71,332	2,202	8,770
15	Constr Work In Progress		418,546	142,040	274,591	14,907	259,683	189,096	48,077	21,825	686	1,916
16	Fuel Inventory		74,663	21,829	52,516	2,488	50,028	35,892	9,300	4,695	141	317
17	Materials & Supplies		116,514	39,258	76,616	4,135	72,481	52,757	13,402	6,129	193	639
18	Prepayments		164,602	66,311	97,099	6,282	90,817	67,326	16,275	7,000	216	1,191
19	Non-Plant & Work Cash		(91,634)	(37,372)	(53,278)	(3,542)	(49,735)	(36,918)	(8,879)	(3,821)	(117)	(985)
20	Total Additions		682,690	232,066	447,545	24,271	423,274	308,153	78,175	35,827	1,119	3,078
21	**Rate Base**		7,078,221	2,787,166	4,237,934	267,219	3,970,715	2,935,574	715,467	310,089	9,584	53,121
	Income Statement											
22A	**Tot Oper Rev - Pres**		3,494,761	1,236,545	2,229,840	131,454	2,098,386	1,562,795	364,429	165,354	5,807	28,377
22B	**Tot Oper Rev - Prop**		3,662,846	1,297,497	2,335,409	137,883	2,197,526	1,637,113	381,289	173,041	6,082	29,940
23	Oper & Maint		2,446,292	818,709	1,612,199	89,160	1,523,039	1,109,808	282,163	126,936	4,132	15,384
24	Book Depr + IRS Int		355,267	133,665	216,627	13,080	203,546	149,601	36,997	16,451	498	4,975
25	Payroll, Rl Est & Prop Tax		187,780	76,469	109,299	7,261	102,038	75,728	18,223	7,846	241	2,011
26	Deferred Inc Tax & Net ITC		176,782	73,885	101,619	6,915	94,704	70,650	16,893	6,940	221	1,277
27A	Present Income Tax		(65,121)	(23,577)	(42,214)	(1,429)	(40,785)	(18,803)	(16,255)	(5,746)	19	670
27B	Proposed Income Tax		4,416	1,639	1,460	1,231	230	11,942	(9,280)	(2,566)	133	1,317
28	Allow Funds Dur Const		29,355	9,995	19,218	1,047	18,171	13,241	3,364	1,518	48	143
29A	**Present Return**		423,117	167,388	251,527	17,513	234,013	189,051	29,772	14,446	744	4,202
29B	**Proposed Return**		521,665	203,124	313,422	21,283	292,139	232,624	39,658	18,953	905	5,118
30A	**Pres Ret on Rt Base**		5.98%	6.01%	5.94%	6.55%	5.89%	6.44%	4.16%	4.66%	7.76%	7.91%
30B	**Prop Ret on Rt Base**		**7.37%**	7.29%	7.40%	7.96%	7.36%	7.92%	5.54%	6.11%	9.44%	9.64%
31A	**Pres Ret on Common**		7.06%	7.12%	6.98%	8.16%	6.90%	7.94%	3.60%	4.55%	10.46%	10.74%
31B	**Prop Ret on Common**		**9.71%**	9.56%	9.76%	10.85%	9.69%	10.77%	6.23%	7.32%	13.66%	14.03%

PRES vs Equal Rev Reqts

			1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	**UnAdj Equal Rev Reqt @ 7.37%**		**2,994,440**	**1,087,755**	**1,880,856**	**111,792**	**1,769,064**	**1,297,623**	**323,064**	**143,807**	**4,569**	**25,829**
2	**Present Revenue**		**2,826,661**	**1,023,121**	**1,777,221**	**108,086**	**1,669,134**	**1,251,116**	**283,915**	**129,470**	**4,633**	**26,319**
3	**UnAdj Revenue Deficiency**		**167,779**	**64,634**	**103,635**	**3,706**	**99,930**	**46,507**	**39,148**	**14,338**	**(64)**	**(490)**
4	**UnAdj Deficiency / Present**		**5.94%**	**6.32%**	**5.83%**	**3.43%**	**5.99%**	**3.72%**	**13.79%**	**11.07%**	**-1.38%**	**-1.86%**
			[TRADE SECRET BEGINS									
5	**Pres Rate Discounts**											
6	**Pres Rate Discount Cost Alloc**	**DiscAlloc**										
											TRADE SECRET ENDS]	
7	**Revenue Requirement Shift**		**0**	**(614)**	**602**	**1,811**	**(1,209)**	**7,933**	**(1,329)**	**(7,597)**	**(215)**	**13**
8	**Adj Equal Rev Reqt (Rows 1+7)**		**2,994,440**	**1,087,141**	**1,881,458**	**113,603**	**1,767,855**	**1,305,556**	**321,735**	**136,210**	**4,354**	**25,841**
9	**Adj Rev Defic vs Pres Rev (Row 2)**		**167,779**	**64,019**	**104,237**	**5,516**	**98,721**	**54,440**	**37,819**	**6,740**	**(279)**	**(478)**
10	**Adj Deficiency / Adj Present**		**5.94%**	**6.26%**	**5.87%**	**5.10%**	**5.91%**	**4.35%**	**13.32%**	**5.21%**	**-6.02%**	**-1.81%**
	Equal Customer Classification											
11	Min Sys & Service Drop		197,940	161,131	20,096	11,821	8,276	7,903	339	27	7	16,712
12	Energy Services		57,731	47,682	9,661	5,522	4,139	4,070	64	3	2	388
13	Total Customer **(Cusco)**		255,671	208,813	29,757	17,343	12,414	11,973	403	30	9	17,101
14	Ave Monthly Customers		1,272,915	1,113,587	132,467	86,824	45,642	45,146	469	17	10	26,861
15	Svc Drop Reqt	$ / Mo / Cust	$12.96	$12.06	$12.64	$11.35	$15.11	$14.59	$60.31	$127.01	$60.37	$51.85
16	Ener Svcs Reqt	$ / Mo / Cust	$3.78	$3.57	$6.08	$5.30	$7.56	$7.51	$11.30	$15.14	$15.14	$1.21
17	Total Reqt	$ / Mo / Cust	$16.74	$15.63	$18.72	$16.65	$22.67	$22.10	$71.61	$142.15	$75.51	$53.05
	Equal Energy Classification											
18	On Peak Rev Reqt		748,326	203,823	543,108	28,710	514,398	375,445	94,644	42,914	1,394	1,395
19	Off Peak Rev Reqt		693,258	217,267	471,156	19,311	451,844	319,603	84,814	46,078	1,350	4,836
20	Total Ener Rev Reqt		1,441,583	421,090	1,014,263	48,021	966,242	695,048	179,458	88,992	2,744	6,231
21	Annual MWh Sales		30,773,807.855	8,756,626	21,843,303	968,021	20,875,282	14,759,156	3,939,474	2,115,136	61,516	173,879
22	On Pk Reqt	Mills / kWh	24.317	23.276	24.864	29.659	24.641	25.438	24.025	20.289	22.667	8.023
23	Off Pk Reqt	Mills / kWh	22.528	24.812	21.570	19.949	21.645	21.655	21.529	21.785	21.941	27.810
24	Total Reqt	Mills / kWh	46.844	48.088	46.434	49.608	46.286	47.093	45.554	42.074	44.608	35.833
	Equal Demand Classification											
25	Energy-Related Prod		300,716	90,087	209,525	10,178	199,347	143,609	37,209	17,972	557	1,104
26	Capacity-Related Summer Peak Prod		391,222	134,841	256,216	14,453	241,763	179,614	46,181	15,328	639	164
27	Capacity-Related Winter Peak Prod		146,361	50,446	95,854	5,407	90,447	67,196	17,277	5,734	239	61
28	Total Capacity-Related Prod		537,583	185,287	352,070	19,860	332,210	246,810	63,458	21,063	878	225
29	Total Production		838,299	275,374	561,596	30,039	531,557	390,419	100,667	39,034	1,436	1,329
30	Transmission **(Transco)**		238,794	82,797	155,991	8,854	147,137	108,408	28,074	10,274	380	7
31	Primary Dist Subs		83,990	31,663	51,825	2,861	48,964	34,693	8,793	5,477	0	502
32	Prim Dist Lines		64,212	32,027	31,805	2,084	29,721	24,053	5,668	0	0	379
33	Second Dist, Trans		71,891	35,991	35,619	2,590	33,029	33,029	0	0	0	280
34	Total Distribution **(Disco)**		220,093	99,681	119,250	7,535	111,714	91,775	14,462	5,477	0	1,162
35	Total Demand Rev Reqt		1,297,186	457,853	836,836	46,428	790,408	590,603	143,203	54,785	1,816	2,498
36	Annual Billing kW		53,267,029	0	53,267,029	0	53,267,029	40,423,684	8,517,989	4,077,194	248,162	0
37	Base Rev Reqt	$ / kW	$0.00	$0.00	$3.93	$0.00	$3.74	$3.55	$4.37	$4.41	$2.25	$0.00
38	Summer Rev Reqt	$ / kW	$0.00	$0.00	$4.81	$0.00	$4.54	$4.44	$5.42	$3.76	$2.58	$0.00
39	Winter Rev Reqt	$ / kW	$0.00	$0.00	$1.80	$0.00	$1.70	$1.66	$2.03	$1.41	$0.96	$0.00
40	Prod Rev Reqt	$ / kW	$0.00	$0.00	$10.54	$0.00	$9.98	$9.66	$11.82	$9.57	$5.79	$0.00
41	Tran Rev Reqt	$ / kW	$0.00	$0.00	$2.93	$0.00	$2.76	$2.68	$3.30	$2.52	$1.53	$0.00
42	Dist Rev Reqt	$ / kW	$0.00	$0.00	$2.24	$0.00	$2.10	$2.27	$1.70	$1.34	$0.00	$0.00
43	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$15.71	$0.00	$14.84	$14.61	$16.81	$13.44	$7.32	$0.00
44	Tot Dmd Rev Reqt	Mills / kWh	42.152	52.286	38.311	47.962	37.863	40.016	36.351	25.902	29.525	14.364
45	Summer Billing kW		19,423,061	0	19,423,061	0	19,423,061	14,775,201	3,164,410	1,392,494	90,956	0
46	Winter Billing kW		33,843,967	0	33,843,967	0	33,843,967	25,648,483	5,353,579	2,684,700	157,205	0
47	Tot Summer Reqt	$ / kW	$0.00	$0.00	$22.29	$0.00	$21.05	$20.66	$23.96	$19.28	$10.81	$0.00
48	Tot Winter Reqt	$ / kW	$0.00	$0.00	$11.93	$0.00	$11.27	$11.12	$12.59	$10.41	$5.30	$0.00
49	Energy + Production **(Genco)**		2,279,882	696,464	1,575,859	78,060	1,497,799	1,085,467	280,125	128,027	4,180	7,560

PROP vs Equal Rev Reqts

			1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
	Total Retail Rev Reqt	Alloc	MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
1	**Proposed Ret On Rt Base**		**7.37%**	**7.29%**	**7.40%**	**7.96%**	**7.36%**	**7.92%**	**5.54%**	**6.11%**	**9.44%**	**9.64%**
2	**UnAdj Equalized Rev Reqt**		**2,994,440**	**1,087,755**	**1,880,856**	**111,792**	**1,769,064**	**1,297,623**	**323,064**	**143,807**	**4,569**	**25,829**
3	**Proposed Revenue**		**2,994,440**	**1,083,849**	**1,882,709**	**114,502**	**1,768,207**	**1,325,377**	**300,768**	**137,154**	**4,908**	**27,881**
4	**UnAdj Revenue Deficiency**		**(0)**	**3,906**	**(1,853)**	**(2,710)**	**857**	**(27,754)**	**22,296**	**6,653**	**(339)**	**(2,052)**
5	**UnAdj Deficiency / Proposed**		**0.00%**	**0.36%**	**-0.10%**	**-2.37%**	**0.05%**	**-2.09%**	**7.41%**	**5%**	**-7%**	**-7.36%**
6	**Prop Rate Discounts**		**171,636**	**56,138**	**114,775**	**4,879**	**109,896**	**71,891**	**21,370**	**16,104**	**531**	**724**
7	**Prop Rate Discount Cost Alloc**	**DiscAlloc**	**171,636**	**59,867**	**111,739**	**6,392**	**105,347**	**78,056**	**20,167**	**6,850**	**274**	**31**
8	**Revenue Requirement Shift**		**0**	**3,729**	**(3,036)**	**1,514**	**(4,549)**	**6,165**	**(1,203)**	**(9,254)**	**(257)**	**(693)**
9	**Adj Equal Rev (Rows 2+8)**		**2,994,440**	**1,091,484**	**1,877,821**	**113,306**	**1,764,515**	**1,303,788**	**321,861**	**134,553**	**4,312**	**25,135**
10	**Adj Rev Defic vs Prop Rev (Row 3)**		**(0)**	**7,635**	**(4,889)**	**(1,196)**	**(3,692)**	**(21,589)**	**21,094**	**(2,601)**	**(596)**	**(2,746)**
11	**Adj Deficiency / Adj Prop**		**0.00%**	**0.70%**	**-0.26%**	**-1.04%**	**-0.21%**	**-1.63%**	**7.01%**	**-1.90%**	**-12.14%**	**-9.85%**
	Prop Customer Component											
12	Min Sys & Service Drop		196,476	157,963	20,469	12,113	8,356	8,021	303	25	8	18,045
13	Energy Services		57,733	47,684	9,661	5,522	4,139	4,070	64	3	2	388
14	Total Customer **(Cusco)**		254,209	205,647	30,130	17,636	12,494	12,091	366	28	9	18,433
15	Ave Monthly Customers		1,272,915	1,113,587	132,467	86,824	45,642	45,146	469	17	10	26,861
16	Svc Drop Reqt	$ / Mo / Cust	$12.86	$11.82	$12.88	$11.63	$15.26	$14.81	$53.85	$116.99	$64.99	$55.98
17	Ener Svcs Reqt	$ / Mo / Cust	$3.78	$3.57	$6.08	$5.30	$7.56	$7.51	$11.31	$15.14	$15.14	$1.20
18	Total Reqt	$ / Mo / Cust	$16.64	$15.39	$18.95	$16.93	$22.81	$22.32	$65.15	$132.13	$80.13	$57.19
	Prop Energy Component											
19	On Peak Rev Reqt		748,047	203,748	542,902	28,715	514,187	375,477	94,463	42,850	1,396	1,397
20	Off Peak Rev Reqt		692,987	217,187	470,957	19,314	451,643	319,630	84,652	46,010	1,351	4,844
21	Total Ener Rev Reqt		1,441,034	420,935	1,013,859	48,029	965,829	695,107	179,114	88,860	2,748	6,241
22	Annual MWh Sales		30,773,808	8,756,626	21,843,303	968,021	20,875,282	14,759,156	3,939,474	2,115,136	61,516	173,879
23	On Pk Reqt	Mills / kWh	24.308	23.268	24.854	29.664	24.631	25.440	23.979	20.259	22.697	8.035
24	Off Pk Reqt	Mills / kWh	22.519	24.803	21.561	19.952	21.635	21.656	21.488	21.753	21.969	27.857
25	Total Reqt	Mills / kWh	46.827	48.070	46.415	49.616	46.267	47.097	45.467	42.012	44.666	35.891
	Prop Demand Component											
26	Energy-Related Prod		309,388	92,857	214,879	11,548	203,330	161,015	27,023	14,529	763	1,653
27	Capacity-Related Summer Peak Prod		388,975	134,038	254,772	14,712	240,060	182,123	42,766	14,489	682	164
28	Capacity-Related Winter Peak Prod		145,521	50,146	95,314	5,504	89,810	68,135	15,999	5,421	255	61
29	Total Capacity-Related Prod		534,495	184,184	350,086	20,216	329,870	250,258	58,766	19,910	937	225
30	Total Production		843,883	277,041	564,964	31,764	533,201	411,273	85,789	34,439	1,699	1,878
31	Transmission **(Transco)**		237,512	82,361	155,144	9,354	145,790	113,487	22,936	8,915	452	7
32	Primary Dist Subs		82,605	31,179	50,849	2,942	47,907	35,435	7,560	4,912	0	577
33	Prim Dist Lines		63,422	31,506	31,492	2,123	29,369	24,368	5,001	0	0	423
34	Second Dist, Trans		71,775	35,181	36,271	2,655	33,617	33,617	0	0	0	323
35	Total Distribution **(Disco)**		217,801	97,866	118,612	7,719	110,893	93,419	12,561	4,912	0	1,323
36	Total Demand Rev Reqt		1,299,196	457,268	838,720	48,837	789,884	618,179	121,287	48,267	2,151	3,208
37	Annual Billing kW		53,267,029	0	53,267,029	0	53,267,029	40,423,684	8,517,989	4,077,194	248,162	0
38	Base Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$3.82	$3.98	$3.17	$3.56	$3.07	$0.00
39	Summer Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$4.51	$4.51	$5.02	$3.55	$2.75	$0.00
40	Winter Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$1.69	$1.69	$1.88	$1.33	$1.03	$0.00
41	Prod Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$10.01	$10.17	$10.07	$8.45	$6.85	$0.00
42	Tran Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$2.74	$2.81	$2.69	$2.19	$1.82	$0.00
43	Dist Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$2.08	$2.31	$1.47	$1.20	$0.00	$0.00
44	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$14.83	$15.29	$14.24	$11.84	$8.67	$0.00
45	Tot Dmd Rev Reqt	Mills / kWh	42.218	52.220	38.397	50.450	37.838	41.884	30.788	22.820	34.967	18.447
46	Summer Billing kW		19,423,061	0	19,423,061	0	19,423,061	14,775,201	3,164,410	1,392,494	90,956	0
47	Winter Billing kW		33,843,967	0	33,843,967	0	33,843,967	25,648,483	5,353,579	2,684,700	157,205	0
48	Tot Summer Reqt	$ / kW	$0.00	$0.00	$22.29	$0.00	$21.00	$21.43	$20.85	$17.36	$12.39	$0.00
49	Tot Winter Reqt	$ / kW	$0.00	$0.00	$11.99	$0.00	$11.29	$11.76	$10.33	$8.97	$6.52	$0.00
50	Energy + Production **(Genco)**		2,284,918	697,975	1,578,823	79,793	1,499,030	1,106,380	264,904	123,299	4,447	8,119
51	Prop Rev - Pres Rev (Pg 2)		167,779	60,728	105,489	6,416	99,073	74,261	16,852	7,685	275	1,562
52	Difference / Present		5.94%	5.94%	5.94%	5.94%	5.94%	5.94%	5.94%	5.94%	5.94%	5.94%

Original Plant in Service

				1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Summer Peak	D10S		1,587,760	553,402	1,034,358	59,104	975,254	722,454	187,087	63,181	2,532	0
2	WInter Peak	D10S		594,002	207,035	386,967	22,112	364,855	270,279	69,992	23,637	947	0
3	Total Peak	D10S		2,181,762	760,438	1,421,324	81,215	1,340,109	992,733	257,079	86,818	3,479	0
4	Base Load	E8760		4,545,700	1,329,017	3,197,364	151,502	3,045,862	2,185,199	566,207	285,856	8,601	19,319
5	Nuclear Fuel	E8760		1,872,449	547,444	1,317,047	62,406	1,254,641	900,119	233,230	117,749	3,543	7,958
6	Total	32.43%	120, 310-346	8,599,911	2,636,898	5,935,735	295,123	5,640,612	4,078,051	1,056,515	490,422	15,623	27,277
	Transmission												
7	Gen Step Up Base	E8760		42,586	12,451	29,954	1,419	28,535	20,472	5,304	2,678	81	181
8	Gen Step Up Peak	D10S		20,440	7,124	13,316	761	12,555	9,300	2,408	813	33	0
9	Total Gen Step Up			63,026	19,575	43,270	2,180	41,090	29,772	7,713	3,491	113	181
10	Bulk Transmission	D10S		2,010,591	700,777	1,309,814	74,844	1,234,970	914,848	236,910	80,006	3,206	0
11	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign		7,365	0	7,365	0	7,365	147	0	7,217	0	0
13	Total		350-359	2,080,982	720,352	1,360,449	77,024	1,283,425	944,767	244,623	90,715	3,319	181
	Distribution:												
	Substations												
14	Generat Step Up	STRATH		3,095	930	2,155	105	2,050	1,477	383	185	6	11
15	Bulk Transmission	D10S		1,611	562	1,050	60	990	733	190	64	3	0
16	Distrib Function	D60Sub		562,586	218,874	340,251	19,750	320,501	238,813	60,605	21,083	0	3,461
17	Direct Assign	Dir Assign		16,927	0	16,927	0	16,927	339	0	16,588	0	0
18	Total		360-363	584,220	220,366	360,382	19,915	340,467	241,362	61,178	37,919	8	3,472
	Overhead Lines												
19	Primary Capacity 1 Phase	D61PS1Ph		91,191	69,706	20,795	3,223	17,572	15,576	1,996	0	0	691
20	Primary Capacity Multi Phase	D61PS		157,859	55,510	101,567	4,870	96,697	76,949	19,748	0	0	783
21	Primary Customer 1 Phase	C61PS1Ph		57,804	55,036	2,625	2,263	363	361	2	0	0	142
22	Primary Customer Multi Phase	C61PS		100,062	89,120	10,615	6,954	3,661	3,624	38	0	0	328
23	Total Primary			406,916	269,371	135,602	17,309	118,293	96,510	21,783	0	0	1,943
24	Second Capacity	D62SecL		99,059	47,802	50,839	3,663	47,176	47,176	0	0	0	418
25	Second Customer	C62Sec		99,984	89,084	10,573	6,951	3,622	3,622	0	0	0	328
26	Total Secondary			199,044	136,886	61,412	10,614	50,798	50,798	0	0	0	746
27	Street Lighting	DASL		35,236	0	0	0	0	0	0	0	0	35,236
28	Total		364,365	641,196	406,258	197,014	27,923	169,090	147,307	21,783	0	0	37,924
	Underground Lines												
29	Primary Capacity 1 Phase	D61PS1Ph		38,727	29,602	8,831	1,369	7,462	6,615	848	0	0	293
30	Primary Capacity Multi Phase	D61PS		61,451	21,609	39,538	1,896	37,642	29,955	7,687	0	0	305
31	Primary Customer 1 Phase	C61PS1Ph		189,302	180,238	8,598	7,411	1,187	1,181	6	0	0	466
32	Primary Customer Multi Phase	C61PS		300,385	267,536	31,865	20,874	10,991	10,878	113	0	0	984
33	Total Primary			589,865	498,985	88,832	31,549	57,283	48,629	8,654	0	0	2,047
34	Second Capacity	D62SecL		241,096	116,344	123,734	8,916	114,818	114,818	0	0	0	1,018
35	Second Customer	C62Sec		266,273	237,244	28,157	18,511	9,646	9,646	0	0	0	872
36	Total Secondary			507,369	353,588	151,891	27,427	124,464	124,464	0	0	0	1,890
37	Street Lighting	DASL		0	0	0	0	0	0	0	0	0	0
38	Total		366,367	1,097,233	852,573	240,723	58,976	181,747	173,093	8,654	0	0	3,938
	Line Transformers												
39	Primary	D61PS		17,396	6,117	11,193	537	10,656	8,480	2,176	0	0	86
40	Second Capacity	D62SecL		166,494	80,344	85,447	6,157	79,290	79,290	0	0	0	703
41	Second Customer	C62Sec		139,462	124,258	14,747	9,695	5,052	5,052	0	0	0	457
42	Total		368	323,352	210,718	111,387	16,389	94,998	92,822	2,176	0	0	1,246
	Services												
43	Second Capacity	D62NLL		63,698	46,021	17,677	1,576	16,101	16,101	0	0	0	0
44	Second Customer	C62NL		169,202	159,752	9,450	6,213	3,238	3,238	0	0	0	0
45	Total		369	232,900	205,773	27,127	7,789	19,338	19,338	0	0	0	0
46	Meters	C12WM	370	96,003	65,157	30,665	10,477	20,188	18,154	1,839	154	41	181
47	Street Lighting	Dir Assign	373	54,364	0	0	0	0	0	0	0	0	54,364
48	**Total Distribution**			3,029,267	1,960,844	967,298	141,469	825,829	692,076	95,630	38,073	49	101,125
49	**General & Common Plant**	PTD	303, 389-399	970,067	376,284	584,685	36,341	548,344	404,359	98,829	43,812	1,344	9,098
50	Prelim Elec Plant			14,680,227	5,694,379	8,848,167	549,957	8,298,210	6,119,254	1,495,597	663,023	20,336	137,681
51	TBT Investment	NEPIS		0	0	0	0	0	0	0	0	0	0
52	**Elec Plant in Serv**			14,680,227	5,694,379	8,848,167	549,957	8,298,210	6,119,254	1,495,597	663,023	20,336	137,681

	Accum Deprec; Net Plant			1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		972,119	338,825	633,294	36,187	597,107	442,328	114,546	38,683	1,550	0
2	Decom Int Peaking	D10S		0	0	0	0	0	0	0	0	0	0
3	Decom Int Baseload	E8760		0	0	0	0	0	0	0	0	0	0
4	Nuclear Fuel	E8760		1,668,310	487,760	1,173,459	55,602	1,117,857	801,986	207,803	104,911	3,157	7,090
5	Base Load	E8760		1,867,352	545,954	1,313,462	62,236	1,251,226	897,669	232,595	117,428	3,533	7,936
6	Total		108,111,115,120.5	4,507,780	1,372,539	3,120,215	154,025	2,966,189	2,141,983	554,943	261,023	8,240	15,027
	Transmission												
7	Gen Step Up Base	E8760		3,909	1,143	2,750	130	2,619	1,879	487	246	7	17
8	Gen Step Up Peak	D10S		1,876	654	1,222	70	1,152	854	221	75	3	0
9	Total Gen Step Up			5,786	1,797	3,972	200	3,772	2,733	708	320	10	17
10	Bulk Transmission	D10S		508,267	177,153	331,114	18,920	312,194	231,269	59,890	20,225	811	0
11	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign		2,025	0	2,025	0	2,025	40	0	1,984	0	0
13	Total		108,111,115,120.5	516,077	178,950	337,111	19,120	317,991	234,042	60,598	22,530	821	17
	Distribution												
14	Generat Step Up	STRATH		1,661	499	1,156	56	1,100	792	205	99	3	6
15	Bulk Transmission	D10S		645	225	420	24	396	294	76	26	1	0
16	Distrib Function	D60Sub		198,996	77,419	120,352	6,986	113,367	84,472	21,437	7,457	0	1,224
17	Direct Assign	Dir Assign		7,212	0	7,212	0	7,212	144	0	7,068	0	0
18	Total Substations			208,514	78,143	129,141	7,066	122,075	85,702	21,718	14,650	4	1,230
19	Overhead Lines	POL		203,443	128,900	62,510	8,860	53,650	46,739	6,911	0	0	12,033
20	Underground	PUL		415,438	322,804	91,143	22,330	68,814	65,537	3,277	0	0	1,491
21	Line Transformers	P68		102,607	66,866	35,346	5,201	30,145	29,455	691	0	0	395
22	Services	P69		92,372	81,613	10,759	3,089	7,670	7,670	0	0	0	0
23	Meters	C12WM		38,503	26,132	12,299	4,202	8,097	7,281	738	62	17	73
24	Street Lighting	P73		44,624	0	0	0	0	0	0	0	0	44,624
25	Total		108,111,115,120.5	1,105,502	704,458	341,198	50,747	290,450	242,383	33,335	14,711	21	59,846
26	**General Plant**	PTD	108,111,115,120.5	424,327	164,594	255,753	15,896	239,857	176,875	43,230	19,164	588	3,980
27	**Electric Common**	PTD	108,111,115,120.5	0	0	0	0	0	0	0	0	0	0
28	**Total Accum Depr**			6,553,686	2,420,541	4,054,276	239,789	3,814,487	2,795,284	692,105	317,428	9,669	78,869
29	**Net Elec Plant**			8,126,541	3,273,838	4,793,891	310,168	4,483,723	3,323,970	803,492	345,594	10,666	58,812
30	**Net Plant w/ TBT**			8,126,541	3,273,838	4,793,891	310,168	4,483,723	3,323,970	803,492	345,594	10,666	58,812
	Subtractions: Accum Defer Inc Tax												
	Production												
31	Peaking Plant	D10S		260,022	90,629	169,393	9,679	159,714	118,314	30,639	10,347	415	0
32	Base Load	E8760		687,492	201,001	483,569	22,913	460,656	330,489	85,633	43,233	1,301	2,922
33	Nuclear Fuel	E8760		37,373	10,927	26,287	1,246	25,042	17,966	4,655	2,350	71	159
34	Total		190,281,282,283	984,886	302,556	679,250	33,838	645,412	466,769	120,927	55,930	1,786	3,081
	Transmission												
35	Gen Step Up Base	E8760		11,911	3,482	8,378	397	7,981	5,726	1,484	749	23	51
36	Gen Step Up Peak	D10S		5,717	1,992	3,724	213	3,511	2,601	674	227	9	0
37	Total Gen Step Up			17,627	5,475	12,102	610	11,492	8,327	2,157	976	32	51
38	Bulk Transmission	D10S		387,368	135,014	252,354	14,420	237,934	176,258	45,644	15,414	618	0
39	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
40	Direct Assign	Dir Assign		1,402	0	1,402	0	1,402	28	0	1,374	0	0
41	Total		281,282,283	406,398	140,489	265,858	15,029	250,829	184,613	47,801	17,765	649	51
	Distribution												
42	Generat Step Up	STRATH		576	173	401	20	381	275	71	34	1	2
43	Bulk Transmission	D10S		228	80	149	9	140	104	27	9	0	0
44	Distrib Function	D60Sub		88,291	34,350	53,398	3,100	50,299	37,479	9,511	3,309	0	543
45	Direct Assign	Dir Assign		2,146	0	2,146	0	2,146	43	0	2,103	0	0
46	Total Substations			91,241	34,602	56,094	3,128	52,966	37,900	9,609	5,455	1	545
47	Overhead Lines	POL		118,155	74,862	36,304	5,146	31,159	27,145	4,014	0	0	6,988
48	Underground	PUL		203,254	157,932	44,592	10,925	33,667	32,064	1,603	0	0	729
49	Line Transformers	P68		65,475	42,668	22,555	3,319	19,236	18,795	441	0	0	252
50	Services	P69		35,312	31,199	4,113	1,181	2,932	2,932	0	0	0	0
51	Meters	C12WM		18,242	12,381	5,827	1,991	3,836	3,449	349	29	8	34
52	Street Lighting	P73		(1,744)	0	0	0	0	0	0	0	0	(1,744)
53	Total		281,282,283	529,935	353,644	169,484	25,688	143,796	122,286	16,017	5,484	9	6,806
54	**General & Common Plant**	PTD	281,282,283	99,644	38,651	60,058	3,733	56,325	41,535	10,152	4,500	138	935
55	**Total Deferred Tax**			2,020,863	835,341	1,174,650	78,288	1,096,361	815,203	194,896	83,680	2,583	10,872
56	Net Operating Loss (NOL) Carry	NEPIS		(285,007)	(114,817)	(168,127)	(10,878)	(157,249)	(116,575)	(28,179)	(12,120)	(374)	(2,063)
57	Non-Plant Related	LABOR		(4,846)	(1,786)	(3,020)	(191)	(2,830)	(2,078)	(517)	(227)	(7)	(40)
58	**Accum Def W/ Adj**			1,731,010	718,738	1,003,502	67,220	936,283	696,549	166,200	71,332	2,202	8,770

	Additions: CWIP, Etc; Rate Base			1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		32,268	11,247	21,022	1,201	19,820	14,683	3,802	1,284	51	0
2	Base Load	E8760		129,135	37,755	90,831	4,304	86,527	62,077	16,085	8,121	244	549
3	Nuclear Fuel	E8760		109,627	32,051	77,109	3,654	73,456	52,699	13,655	6,894	207	466
4	Total		107	271,030	81,053	188,962	9,159	179,803	129,459	33,542	16,299	503	1,015
	Transmission												
5	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10S		0	0	0	0	0	0	0	0	0	0
7	Total Gen Step Up			0	0	0	0	0	0	0	0	0	0
8	Bulk Transmission	D10S		69,336	24,167	45,170	2,581	42,589	31,549	8,170	2,759	111	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
11	Total		107	69,336	24,167	45,170	2,581	42,589	31,549	8,170	2,759	111	0
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub		7,759	3,018	4,692	272	4,420	3,293	836	291	0	48
15	Direct Assign	Dir Assign		120	0	120	0	120	2	0	117	0	0
16	Total Substations			7,879	3,018	4,812	272	4,540	3,296	836	408	0	48
17	Overhead Lines	POL		2,526	1,601	776	110	666	580	86	0	0	149
18	Underground	PUL		15,413	11,976	3,381	828	2,553	2,431	122	0	0	55
19	Line Transformers	P68		50	33	17	3	15	14	0	0	0	0
20	Services	P69		(76)	(67)	(9)	(3)	(6)	(6)	0	0	0	0
21	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73		158	0	0	0	0	0	0	0	0	158
23	Total		107	25,950	16,560	8,978	1,211	7,767	6,316	1,044	408	0	411
24	**General Plant**	PTD	107	52,230	20,260	31,481	1,957	29,524	21,771	5,321	2,359	72	490
25	**Electric Common**	PTD	107	0	0	0	0	0	0	0	0	0	0
26	**Total CWIP**			418,546	142,040	274,591	14,907	259,683	189,096	48,077	21,825	686	1,916
27	Fuel Inventory	E8760	151,152	74,663	21,829	52,516	2,488	50,028	35,892	9,300	4,695	141	317
	Materials & Supplies												
28	Production	P10		100,313	30,758	69,237	3,442	65,794	47,568	12,324	5,720	182	318
29	Trans & Distr	TD		16,201	8,500	7,380	693	6,687	5,189	1,079	408	11	321
30	Total		154	116,514	39,258	76,616	4,135	72,481	52,757	13,402	6,129	193	639
	Prepayments												
31	Miscellaneous	NEPIS		164,602	66,311	97,099	6,282	90,817	67,326	16,275	7,000	216	1,191
32	Total		235,252,165	164,602	66,311	97,099	6,282	90,817	67,326	16,275	7,000	216	1,191
33	Non-Plant Assets & Liab	LABOR	190,283,	(13,137)	(4,841)	(8,188)	(517)	(7,671)	(5,635)	(1,402)	(615)	(20)	(108)
34	Working Cash	PT0	calculated	(78,497)	(32,531)	(45,089)	(3,025)	(42,064)	(31,283)	(7,477)	(3,207)	(98)	(877)
35	**Total Additions**			682,690	232,066	447,545	24,271	423,274	308,153	78,175	35,827	1,119	3,078
36	**Total Rate Base**			7,078,221	2,787,166	4,237,934	267,219	3,970,715	2,935,574	715,467	310,089	9,584	53,121
37	**Common Rate Base (@ 52.50%)**			3,716,066	1,463,262	2,224,915	140,290	2,084,625	1,541,177	375,620	162,797	5,032	27,888

Operating Rev (Cal Month)

				1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
	Retail Revenue	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Present Rate Revenue	R01; (calc)	440, 442,444,445	2,826,661	1,023,121	1,777,221	108,086	1,669,134	1,251,116	283,915	129,470	4,633	26,319
2	Proposed Rate Revenue	PROREV; (calc)		2,994,440	1,083,849	1,882,709	114,502	1,768,207	1,325,377	300,768	137,154	4,908	27,881
3	Equal Rate Revenue			2,994,440	1,087,755	1,880,856	111,792	1,769,064	1,297,623	323,064	143,807	4,569	25,829
	Other Retail Revenue												
4	Interdepartmental	R01; R02	448	962	348	605	37	568	426	97	44	2	9
5	Gross Earnings Tax	R01; R02	408	0	0	0	0	0	0	0	0	0	0
6	CIP Adjustment to Program Cost	E99XCIP	456	0	0	0	0	0	0	0	0	0	0
7	**Tot Other Retail Rev**			962	348	605	37	568	426	97	44	2	9
	Other Operating Revenue												
8	Interchg Prod Capacity	P10	456	198,304	60,804	136,871	6,805	130,066	94,035	24,362	11,309	360	629
9	Interchg Prod Energy	E8760	456	175,944	51,440	123,756	5,864	117,892	84,579	21,915	11,064	333	748
10	Interchg Tr Bulk Supply	D10S	456	41,350	14,412	26,938	1,539	25,398	18,815	4,872	1,645	66	0
11	PI Monti Return Adj-Peaking	D10S		3,972	1,384	2,587	148	2,440	1,807	468	158	6	0
12	PI Monti Return Adj-Baseload	E8760		16,826	4,919	11,835	561	11,274	8,089	2,096	1,058	32	72
13	Dist Int Sales; Oth Serv	E8760	412,451,456	652	191	458	22	437	313	81	41	1	3
14	Dist Overhd Line Rent	POL	454	3,634	2,302	1,117	158	958	835	123	0	0	215
15	Connection Charges	C11	451	2,173	1,901	226	148	78	77	1	0	0	46
16	Sales For Resale	E8760	447	78,571	22,972	55,266	2,619	52,647	37,771	9,787	4,941	149	334
17	Joint Op Agree-Other PSCo Rev	D10S	456	(4,827)	(1,682)	(3,145)	(180)	(2,965)	(2,196)	(569)	(192)	(8)	0
18	Misc Ancillary Trans Rev	D10S		193,503	67,444	126,059	7,203	118,856	88,047	22,801	7,700	309	0
19	MISO	D10S	456	1,649	575	1,074	61	1,013	750	194	66	3	0
20	Other	D10S	451,456,457	(49,003)	(17,080)	(31,923)	(1,824)	(30,099)	(22,297)	(5,774)	(1,950)	(78)	0
21	Late Pay Chg - Pres	R16C; R02		4,390	3,493	894	206	688	628	59	1	0	3
22	**Tot Other Op - Pres**		450	667,138	213,075	452,014	23,331	428,683	311,253	80,417	35,841	1,173	2,049
23	Incr Misc Serv - Prop	R01,		0	0	0	0	0	0	0	0	0	0
24	Incr Inter-Dept'l - Prop	R01; R02		45	16	28	2	27	20	5	2	0	0
25	Incr Late Pay - Prop	(R16C); R02		261	207	53	12	41	37	4	0	0	0
26	**Tot Other Op - Prop**			667,443	213,299	452,095	23,345	428,750	311,310	80,425	35,843	1,173	2,050
27	**Tot Oper Rev - Pres**			3,494,761	1,236,545	2,229,840	131,454	2,098,386	1,562,795	364,429	165,354	5,807	28,377
28	**Tot Oper Rev - Prop**			3,662,846	1,297,497	2,335,409	137,883	2,197,526	1,637,113	381,289	173,041	6,082	29,940

Operating & Maint (Pg 1 of 2)

				MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
	Production Expen												
29	**Fuel**	E8760	501,518,547	566,923	165,750	398,764	18,895	379,869	272,530	70,615	35,651	1,073	2,409
	Purchased Power												
30	Purchases: Cap Peak	D10S		109,750	38,253	71,497	4,085	67,412	49,938	12,932	4,367	175	0
31	Purchases: Cap Base	D10S		40,840	14,234	26,605	1,520	25,085	18,583	4,812	1,625	65	0
32	Purchases: Demand		555	150,590	52,487	98,103	5,606	92,497	68,520	17,744	5,992	240	0
33	Purchases: Other Energy	E8760	555	505,394	147,761	355,485	16,844	338,641	242,952	62,951	31,782	956	2,148
34	Tot Non-Assoc Purch			655,984	200,248	453,588	22,450	431,138	311,472	80,695	37,774	1,196	2,148
35	Interchg Agr Capacity	P10WoN	557	41,222	12,803	28,300	1,426	26,875	19,472	5,045	2,284	74	118
36	Interchg Agr Energy	E8760	557	18,558	5,426	13,053	619	12,435	8,921	2,312	1,167	35	79
37	Tot Wis Interchg Purch			59,780	18,229	41,354	2,044	39,309	28,394	7,356	3,451	109	197
38	**Tot Purchased Power**			715,764	218,477	494,942	24,494	470,447	339,866	88,052	41,224	1,306	2,345
	Other Production		500,502,505-507 509-514,517,519,520,										
39	Capacity Related	D10S	523-525,528-532,535,	164,279	57,258	107,020	6,115	100,905	74,749	19,357	6,537	262	0
40	Energy Related	E8760	539,543-546,548-550	340,412	99,526	239,440	11,345	228,094	163,642	42,401	21,407	644	1,447
41	Total Other Produc	32.55%	552-554,556,557 575.1-575.8	504,691	156,784	346,460	17,461	329,000	238,391	61,758	27,944	906	1,447
42	**Total Production**			1,787,378	541,011	1,240,166	60,850	1,179,316	850,787	220,425	104,819	3,284	6,201
43	**Transmission Exp**	D10S	560-563, 565-568 570-573	191,916	66,891	125,025	7,144	117,881	87,325	22,614	7,637	306	0

Operating & Maint (Pg 2 of 2)

				1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
	Distribution Expen	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Supervision & Eng'rg	ZDTS	580,590	7,480	4,153	3,027	375	2,653	2,158	364	128	2	300
2	Load Dispatching	T20D80	581	6,130	2,326	3,769	216	3,553	2,636	672	242	2	35
3	Substations	P61	582,591,592	8,616	3,250	5,315	294	5,021	3,560	902	559	0	51
4	Overhead Lines	POL	583,593	36,452	23,096	11,200	1,587	9,613	8,374	1,238	0	0	2,156
5	Underground Lines	PUL	584, 594	15,899	12,354	3,488	855	2,634	2,508	125	0	0	57
6	Line Transformers	P68	595	2,192	1,428	755	111	644	629	15	0	0	8
7	Meters	C12WM	586,597,598	3,279	2,226	1,047	358	690	620	63	5	1	6
8	Customer Install'n	OXDTS	587	3,453	2,058	1,170	157	1,013	840	138	36	0	225
9	Street Lighting	Dir Assign	585,596	2,611	0	0	0	0	0	0	0	0	2,611
10	Miscellaneous	OXDTS	588	13,968	8,324	4,733	634	4,098	3,397	557	144	1	911
11	Rents (Pole Attachmts)	POL	589	3,238	2,051	995	141	854	744	110	0	0	191
12	**Total Distribution**			103,317	61,265	35,500	4,728	30,772	25,466	4,185	1,114	7	6,553
13	**Customer Accounting**	C11WA	901-905	48,049	39,624	8,126	4,634	3,492	3,434	54	3	2	299
14	**Sales, Econ Dvlp & Other**	R01	912	101	37	64	4	60	45	10	5	0	1
	Admin & General												
15	Salaries	LABOR	920	44,771	16,498	27,906	1,763	26,143	19,203	4,777	2,096	67	367
16	Office Supplies	OXTS	921	42,250	14,138	27,846	1,540	26,306	19,168	4,874	2,193	71	266
17	Admin Transfer Credit	OXTS	922	(31,886)	(10,670)	(21,015)	(1,162)	(19,853)	(14,466)	(3,679)	(1,655)	(54)	(200)
18	Outside Services	LABOR	923	16,467	6,068	10,264	648	9,616	7,063	1,757	771	25	135
19	Property Insurance	NEPIS	924	6,472	2,607	3,818	247	3,571	2,647	640	275	8	47
20	Pensions & Benefits	LABOR	926	68,121	25,102	42,460	2,682	39,778	29,218	7,269	3,189	102	559
21	Injuries & Claims	LABOR	925	16,036	5,909	9,995	631	9,364	6,878	1,711	751	24	132
22	Regulatory Exp	R01; R02	928	3,430	1,242	2,157	131	2,025	1,518	345	157	6	32
23	General Advertising	OXTS	930.1	1,134	379	747	41	706	514	131	59	2	7
24	Contributions	OXTS		0	0	0	0	0	0	0	0	0	0
25	Misc General Exp	OXTS	929, 930.2	596	199	393	22	371	270	69	31	1	4
26	Rents	OXTS	931	22,979	7,690	15,145	837	14,308	10,425	2,651	1,193	39	144
27	Maint of General Plant	OXTS	935	371	124	245	14	231	168	43	19	1	2
28	Total			190,741	69,286	119,960	7,395	112,565	82,607	20,589	9,077	292	1,495
	Cust Service & Info												
29	Cust Assist Exp - Non-CIP	C11P10	908	2,022	1,194	803	104	699	515	125	58	2	25
30	CIP Total	E99XCIP	908	90,716	27,423	62,748	3,031	59,717	46,012	10,776	2,737	193	544
31	Instructional Advertising	C11P10	909	752	444	299	39	260	192	46	21	1	9
32	Total			93,490	29,062	63,850	3,173	60,677	46,719	10,947	2,816	195	578
33	Amortizations	LABOR		31,300	11,534	19,509	1,232	18,277	13,425	3,340	1,465	47	257
34	**Total O&M Expense**			2,446,292	818,709	1,612,199	89,160	1,523,039	1,109,808	282,163	126,936	4,132	15,384

Northern States Power Company
Electric Utility - State of Minnesota
2015 Compliance CCOSS Detail

	Book Depreciation			1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		72,012	25,099	46,913	2,681	44,232	32,767	8,485	2,866	115	0
2	Base Load	E8760		154,988	45,313	109,016	5,166	103,850	74,505	19,305	9,746	293	659
3	Total		403,413	227,000	70,413	155,929	7,846	148,082	107,272	27,790	12,612	408	659
	Transmission												
4	Gen Step Up Base	E8760		(19,456)	(5,688)	(13,685)	(648)	(13,037)	(9,353)	(2,423)	(1,223)	(37)	(83)
5	Gen Step Up Peak	D10S		(9,338)	(3,255)	(6,083)	(348)	(5,736)	(4,249)	(1,100)	(372)	(15)	0
6	Total Gen Step Up			(28,794)	(8,943)	(19,768)	(996)	(18,772)	(13,602)	(3,524)	(1,595)	(52)	(83)
7	Bulk Transmission	D10S		31,413	10,949	20,464	1,169	19,295	14,293	3,701	1,250	50	0
8	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
9	Direct Assign	Dir Assign		170	0	170	0	170	3	0	166	0	0
10	Total		403,413	2,788	2,006	865	173	692	695	178	(179)	(2)	(83)
	Distribution												
11	Generat Step Up	STRATH		90	27	62	3	59	43	11	5	0	0
12	Bulk Transmission	D10S		49	17	32	2	30	22	6	2	0	0
13	Distrib Function	D60Sub		12,626	4,912	7,636	443	7,193	5,360	1,360	473	0	78
14	Direct Assign	Dir Assign		591	0	591	0	591	12	0	579	0	0
15	Total Substations		403,413	13,356	4,956	8,321	448	7,873	5,437	1,377	1,059	0	78
16	Overhead Lines	POL		24,478	15,509	7,521	1,066	6,455	5,624	832	0	0	1,448
17	Underground	PUL		14,065	10,929	3,086	756	2,330	2,219	111	0	0	50
18	Line Transformers	P68		2,121	1,382	731	108	623	609	14	0	0	8
19	Services	P69		2,430	2,147	283	81	202	202	0	0	0	0
20	Meters	C12WM		1,374	932	439	150	289	260	26	2	1	3
21	Street Lighting	P73		2,199	0	0	0	0	0	0	0	0	2,199
22	Total		403,413	60,023	35,856	20,381	2,609	17,772	14,350	2,360	1,061	1	3,786
23	**General Plant**	PTD	403,413	65,456	25,390	39,452	2,452	37,000	27,284	6,669	2,956	91	614
24	**Electric Common**	PTD	403,413	0	0	0	0	0	0	0	0	0	0
25	**Total Book Deprec**		403,404	355,267	133,665	216,627	13,080	203,546	149,601	36,997	16,451	498	4,975
	Real Estate & Property Tax												
	Production												
26	Peaking Plant	D10S		27,065	9,433	17,632	1,007	16,624	12,315	3,189	1,077	43	0
27	Base Load	E8760		56,391	16,487	39,665	1,879	37,785	27,108	7,024	3,546	107	240
28	Total		408.1	83,456	25,920	57,296	2,887	54,409	39,423	10,213	4,623	150	240
	Transmission												
29	Gen Step Up Base	E8760		597	174	420	20	400	287	74	38	1	3
30	Gen Step Up Peak	D10S		286	100	187	11	176	130	34	11	0	0
31	Total Gen Step Up			883	274	606	31	576	417	108	49	2	3
32	Bulk Transmission	D10S		28,170	9,819	18,352	1,049	17,303	12,818	3,319	1,121	45	0
33	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
34	Direct Assign	Dir Assign		103	0	103	0	103	2	0	101	0	0
35	Total		408.1	29,156	10,093	19,061	1,079	17,982	13,237	3,427	1,271	47	3
	Distribution												
36	Generat Step Up	STRATH		47	14	33	2	31	22	6	3	0	0
37	Bulk Transmission	D10S		24	8	16	1	15	11	3	1	0	0
38	Distrib Function	D60Sub		8,498	3,306	5,140	298	4,841	3,607	915	318	0	52
39	Direct Assign	Dir Assign		256	0	256	0	256	5	0	251	0	0
40	Total Substations			8,825	3,329	5,444	301	5,143	3,646	924	573	0	52
41	Overhead Lines	POL		9,685	6,137	2,976	422	2,554	2,225	329	0	0	573
42	Underground	PUL		16,574	12,878	3,636	891	2,745	2,615	131	0	0	59
43	Line Transformers	P68		4,884	3,183	1,683	248	1,435	1,402	33	0	0	19
44	Services	P69		3,518	3,108	410	118	292	292	0	0	0	0
45	Meters	C12WM		1,450	984	463	158	305	274	28	2	1	3
46	Street Lighting	P73		821	0	0	0	0	0	0	0	0	821
47	Total		408.1	45,758	29,619	14,611	2,137	12,474	10,454	1,445	575	1	1,528
48	**General & Common Plant**	PTD	408.1	0	0	0	0	0	0	0	0	0	0
49	**Tot Rl Est & Pr Tax**			158,371	65,632	90,969	6,103	84,866	63,114	15,085	6,469	197	1,770
50	Gross Earnings Tax	R01; R02		0	0	0	0	0	0	0	0	0	0
51	Payroll Taxes	LABOR		29,409	10,837	18,331	1,158	17,173	12,614	3,138	1,377	44	241
52	**Tot Non-Inc Taxes**			187,780	76,469	109,299	7,261	102,038	75,728	18,223	7,846	241	2,011

	Provision For Defer Inc Tax			1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
	Production	Alloc	FERC Accounts	MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
1	Peaking Plant	D10S		3,964	1,382	2,583	148	2,435	1,804	467	158	6	0
2	Nuclear Fuel	E8760		(17,104)	(5,001)	(12,031)	(570)	(11,461)	(8,222)	(2,130)	(1,076)	(32)	(73)
3	Base Load	E8760		22,381	6,543	15,742	746	14,996	10,759	2,788	1,407	42	95
4	Total		410, 411	9,241	2,924	6,294	323	5,971	4,340	1,124	490	16	22
	Transmission												
5	Gen Step Up Base	E8760		8,055	2,355	5,666	268	5,397	3,872	1,003	507	15	34
6	Gen Step Up Peak	D10S		3,866	1,347	2,519	144	2,375	1,759	456	154	6	0
7	Total Gen Step Up			11,921	3,703	8,184	412	7,772	5,631	1,459	660	21	34
8	Bulk Transmission	D10S		34,234	11,932	22,302	1,274	21,027	15,577	4,034	1,362	55	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		204	0	204	0	204	4	0	200	0	0
11	Total		410, 411	46,359	15,634	30,691	1,687	29,004	21,212	5,493	2,223	76	34
	Distribution												
12	Generat Step Up	STRATH		(36)	(11)	(25)	(1)	(24)	(17)	(4)	(2)	(0)	(0)
13	Bulk Transmission	D10S		(2)	(1)	(1)	(0)	(1)	(1)	(0)	(0)	(0)	0
14	Distrib Function	D60Sub		3,792	1,475	2,294	133	2,161	1,610	409	142	0	23
15	Direct Assign	Dir Assign		(75)	0	(75)	0	(75)	(2)	0	(74)	0	0
16	Total Substations			3,679	1,464	2,192	132	2,060	1,590	404	66	(0)	23
17	Overhead Lines	POL		3,616	2,291	1,111	157	954	831	123	0	0	214
18	Underground	PUL		12,427	9,656	2,726	668	2,058	1,960	98	0	0	45
19	Line Transformers	P68		2,593	1,690	893	131	762	744	17	0	0	10
20	Services	P69		872	771	102	29	72	72	0	0	0	0
21	Meters	C12WM		867	588	277	95	182	164	17	1	0	2
22	Street Lighting	P73		244	0	0	0	0	0	0	0	0	244
23	Total		410, 411	24,299	16,460	7,302	1,212	6,089	5,362	659	68	0	537
24	**General & Common Plant**	PTD	410, 411	6,457	2,505	3,892	242	3,650	2,691	658	292	9	61
25	**Net Operating Loss (NOL) Carı**	NEPIS		92,526	37,275	54,582	3,531	51,050	37,846	9,148	3,935	121	670
26	**Non - Plant Related**	LABOR	410, 411	0	0	0	0	0	0	0	0	0	0
27	**Tot Prov For Defer**			178,882	74,799	102,760	6,996	95,764	71,452	17,082	7,007	223	1,324
	Inv Tax Credit; Total Oper Exp												
	Production												
28	Peaking Plant	D10S		(299)	(104)	(195)	(11)	(184)	(136)	(35)	(12)	(0)	0
29	Base Load	E8760		(568)	(166)	(400)	(19)	(381)	(273)	(71)	(36)	(1)	(2)
30	Total		411	(867)	(270)	(594)	(30)	(564)	(409)	(106)	(48)	(2)	(2)
	Transmission												
31	Bulk Transmission	D10S		(477)	(166)	(311)	(18)	(293)	(217)	(56)	(19)	(1)	0
32	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
33	Total		411	(477)	(166)	(311)	(18)	(293)	(217)	(56)	(19)	(1)	0
	Distribution												
34	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
35	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
36	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
37	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
38	Total Substations			0	0	0	0	0	0	0	0	0	0
39	Overhead Lines	POL		(746)	(473)	(229)	(33)	(197)	(171)	(25)	0	0	(44)
40	Underground	PUL		0	0	0	0	0	0	0	0	0	0
41	Line Transformers	P68		0	0	0	0	0	0	0	0	0	0
42	Services	P69		0	0	0	0	0	0	0	0	0	0
43	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
44	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
45	Total		411	(746)	(473)	(229)	(33)	(197)	(171)	(25)	0	0	(44)
46	**General & Common Plant**	PTD	411	(9)	(4)	(6)	(0)	(5)	(4)	(1)	(0)	(0)	(0)
47	**Net Inv Tax Credit**			(2,100)	(913)	(1,140)	(81)	(1,060)	(802)	(189)	(67)	(2)	(47)
48	**Total Operating Exp**			**3,166,121**	**1,102,728**	**2,039,745**	**116,417**	**1,923,328**	**1,405,788**	**354,276**	**158,172**	**5,092**	**23,648**
49A	**Pres Op Inc Before Inc Tax**			**328,641**	**133,817**	**190,095**	**15,037**	**175,058**	**157,007**	**10,153**	**7,182**	**715**	**4,729**
49B	**Prop Op Inc Before Inc Tax**			**496,725**	**194,769**	**295,665**	**21,467**	**274,198**	**231,325**	**27,013**	**14,869**	**990**	**6,292**

Tax Deprec; Inc Tax & Return

				1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		98,158	34,212	63,946	3,654	60,292	44,663	11,566	3,906	157	0
2	Nuclear Fuel	E8760		73,085	21,368	51,407	2,436	48,971	35,133	9,103	4,596	138	311
3	Base Load	E8760		281,643	82,344	198,103	9,387	188,716	135,391	35,081	17,711	533	1,197
4	Total		tax books	452,887	137,924	313,456	15,477	297,979	215,188	55,751	26,213	828	1,508
	Transmission												
5	Gen Step Up Base	E8760		937	274	659	31	628	451	117	59	2	4
6	Gen Step Up Peak	D10S		450	157	293	17	276	205	53	18	1	0
7	Total Gen Step Up			1,387	431	952	48	904	655	170	77	2	4
8	Bulk Transmission	D10S		116,624	40,648	75,975	4,341	71,634	53,066	13,742	4,641	186	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		681	0	681	0	681	14	0	668	0	0
11	Total		tax books	118,692	41,079	77,609	4,389	73,220	53,734	13,912	5,385	188	4
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		35	12	23	1	22	16	4	1	0	0
14	Distrib Function	D60Sub		21,806	8,484	13,188	766	12,423	9,257	2,349	817	0	134
15	Direct Assign	Dir Assign		324	0	324	0	324	6	0	318	0	0
16	Total Substations			22,165	8,496	13,535	767	12,769	9,279	2,353	1,136	0	134
17	Overhead Lines	POL		33,354	21,133	10,248	1,453	8,796	7,663	1,133	0	0	1,973
18	Underground	PUL		44,435	34,527	9,749	2,388	7,360	7,010	350	0	0	159
19	Line Transformers	P68		8,537	5,563	2,941	433	2,508	2,451	57	0	0	33
20	Services	P69		4,842	4,278	564	162	402	402	0	0	0	0
21	Meters	C12WM		3,632	2,465	1,160	396	764	687	70	6	2	7
22	Street Lighting	P73		2,786	0	0	0	0	0	0	0	0	2,786
23	Total		tax books	119,751	76,462	38,197	5,599	32,598	27,491	3,964	1,142	2	5,092
24	**General & Common Plant**	PTD	tax books	66,806	25,914	40,266	2,503	37,763	27,847	6,806	3,017	93	627
25	**Electric Common**	PTD	tax books	0	0	0	0	0	0	0	0	0	0
25	Net Operating Loss (NOL) Carry	NEPIS		287,742	115,919	169,740	10,982	158,758	117,694	28,450	12,237	378	2,082
26	**Total Tax Deprec**			1,045,879	397,298	639,268	38,950	600,319	441,955	108,882	47,994	1,488	9,313
27	Interest Expense		427,431	160,676	63,269	96,201	6,066	90,135	66,638	16,241	7,039	218	1,206
28	Other Tax Timing Differ	LABOR		21,620	7,967	13,476	851	12,625	9,273	2,307	1,012	32	177
29	Total Tax Deductions			1,228,174	468,533	748,945	45,867	703,079	517,865	127,430	56,045	1,738	10,696
	Inc Tax Additions												
30	Book Depreciation			355,267	133,665	216,627	13,080	203,546	149,601	36,997	16,451	498	4,975
31	Deferred Inc Tax & ITC			176,782	73,885	101,619	6,915	94,704	70,650	16,893	6,940	221	1,277
32	Nuclear Fuel Book Burn	E8760		119,366	34,899	83,960	3,978	79,981	57,381	14,868	7,506	226	507
33	Tax Capitalized Leases	PTD		78,224	30,343	47,148	2,930	44,217	32,607	7,969	3,533	108	734
34	Meals & Entertainment	LABOR		(740)	(273)	(461)	(29)	(432)	(317)	(79)	(35)	(1)	(6)
35	Avoided Tax Interest	RTBASE		14,229	5,603	8,520	537	7,982	5,901	1,438	623	19	107
36	Total Tax Additions			743,128	278,122	457,412	27,413	429,999	315,823	78,087	35,018	1,071	7,594
37	**Total Inc Tax Adjustments**			(485,046)	(190,411)	(291,533)	(18,454)	(273,079)	(202,042)	(49,343)	(21,027)	(667)	(3,102)
38A	**Pres Taxable Net Income**			(156,406)	(56,594)	(101,439)	(3,417)	(98,021)	(45,035)	(39,190)	(13,845)	48	1,627
38B	**Prop Taxable Net Income**			11,679	4,357	4,131	3,012	1,119	29,284	(22,330)	(6,158)	323	3,190
39A	Pres Fed & State Inc Tax			(65,121)	(23,577)	(42,214)	(1,429)	(40,785)	(18,803)	(16,255)	(5,746)	19	670
39B	Prop Fed & State Inc Tax			4,416	1,639	1,460	1,231	230	11,942	(9,280)	(2,566)	133	1,317
40A	Pres Preliminary Return	(total); BASE		393,761	157,394	232,309	16,466	215,842	175,810	26,408	12,928	696	4,059
40B	Prop Preliminary Return	(total); BASE		492,309	193,130	294,204	20,236	273,968	219,383	36,293	17,435	857	4,975
41	Total AFUDC			29,355	9,995	19,218	1,047	18,171	13,241	3,364	1,518	48	143
42A	**Present Total Return**			423,117	167,388	251,527	17,513	234,013	189,051	29,772	14,446	744	4,202
42B	**Proposed Total Return**			521,665	203,124	313,422	21,283	292,139	232,624	39,658	18,953	905	5,118
43A	**Pres % Return on Rate Base**			5.98%	6.01%	5.94%	6.55%	5.89%	6.44%	4.16%	4.66%	7.76%	7.91%
43B	**Prop % Return on Rate Base**			7.37%	7.29%	7.40%	7.96%	7.36%	7.92%	5.54%	6.11%	9.44%	9.64%
44A	**Present Common Return**			262,441	104,120	155,325	11,447	143,878	122,414	13,531	7,407	526	2,996
44B	**Proposed Common Return**			360,989	139,856	217,221	15,217	202,004	165,986	23,416	11,914	687	3,912
45A	**Pres % Ret on Common Rt Base**			0	7.12%	6.98%	8.16%	6.90%	7.94%	3.60%	4.55%	10.46%	10.74%
45B	**Prop % Ret on Common Rt Base**			0	9.56%	9.76%	10.85%	9.69%	10.77%	6.23%	7.32%	13.66%	14.03%

Allow For Funds Used During Constr

				1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		2,611	910	1,701	97	1,604	1,188	308	104	4	0
2	Nuclear Fuel	E8760		4,875	1,425	3,429	162	3,267	2,344	607	307	9	21
3	Base Load	E8760		11,513	3,366	8,098	384	7,715	5,535	1,434	724	22	49
4	Total		419.1,432	19,000	5,702	13,229	643	12,585	9,066	2,349	1,135	35	70
	Transmission												
5	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10S		0	0	0	0	0	0	0	0	0	0
7	Total Gen Step Up			0	0	0	0	0	0	0	0	0	0
8	Bulk Transmission	D10S		4,582	1,597	2,985	171	2,814	2,085	540	182	7	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		3	0	3	0	3	0	0	3	0	0
11	Total		419.1,432	4,585	1,597	2,988	171	2,817	2,085	540	185	7	0
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub		528	206	319	19	301	224	57	20	0	3
15	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
16	Total Substations			528	206	319	19	301	224	57	20	0	3
17	Overhead Lines	POL		213	135	66	9	56	49	7	0	0	13
18	Underground	PUL		1,052	818	231	57	174	166	8	0	0	4
19	Line Transformers	P68		4	2	1	0	1	1	0	0	0	0
20	Services	P69		1	1	0	0	0	0	0	0	0	0
21	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73		17	0	0	0	0	0	0	0	0	17
23	Total		419.1,432	1,815	1,162	617	85	533	440	72	20	0	36
24	**General & Common Plant**	PTD	419.1,432	3,956	1,534	2,384	148	2,236	1,649	403	179	5	37
25	**Total AFUDC**			29,355	9,995	19,218	1,047	18,171	13,241	3,364	1,518	48	143

Labor Allocator

				MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
	Production												
26	Other Prod - Cap	D10S		79,091	27,567	51,524	2,944	48,580	35,988	9,319	3,147	126	0
27	Other Prod - Ene	E8760		164,787	48,179	115,908	5,492	110,416	79,216	20,526	10,363	312	700
28	Total		500 through 557	243,878	75,745	167,433	8,436	158,997	115,204	29,845	13,510	438	700
	Transmission												
29	Stepup Subtrans	P5161A		578	179	397	20	377	273	71	32	1	2
30	Bulk Power Subs	D10S		18,423	6,421	12,002	686	11,316	8,383	2,171	733	29	0
31	Total		560 through 571	19,001	6,601	12,399	706	11,693	8,656	2,242	765	30	2
	Distribution												
32	Superv & Eng	ZDTS	580, 590	5,816	3,229	2,354	291	2,063	1,678	283	99	2	233
33	Load Dispatch	D10S	581	5,310	1,851	3,459	198	3,261	2,416	626	211	8	0
34	Substation	P61	582, 592	5,527	2,085	3,409	188	3,221	2,283	579	359	0	33
35	Overhead Lines	POL	583, 593	6,809	4,314	2,092	297	1,796	1,564	231	0	0	403
36	Underground Lines	PUL	584, 594	2,156	1,675	473	116	357	340	17	0	0	8
37	Line Transformer	P68	595	6,611	4,308	2,277	335	1,942	1,898	44	0	0	25
38	Meter	C12WM	586, 597	4,224	2,867	1,349	461	888	799	81	7	2	8
39	Cust Installation	ZDTS	587	2,917	1,619	1,181	146	1,034	842	142	50	1	117
40	Street Lighting	P73	585, 596	620	0	0	0	0	0	0	0	0	620
41	Miscellaneous	OXDTS	588	6,210	3,700	2,104	282	1,822	1,510	248	64	0	405
42	Total			46,199	25,648	18,698	2,314	16,384	13,330	2,251	790	13	1,853
43	**Cust Accounting**	C11WA	901,902,903,904,905	12,198	10,059	2,063	1,176	886	872	14	1	0	76
44	**Sales Expense**	C11P10	912	6	3	2	0	2	1	0	0	0	0
45	**Admin & General**	LABOR	920,921,922,923,924,	120,936	44,564	75,380	4,762	70,618	51,871	12,905	5,661	181	992
46	**Service & Inform**	C11P10	908, 909	1,500	886	596	77	519	382	92	43	1	18
47	**Labor**			443,718	163,506	276,571	17,471	259,099	190,316	47,349	20,769	664	3,641

			1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
INTERNAL ALLOCATORS		Intern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	50% Cus, 50% Prod Plt	C11P10	100.00%	59.07%	39.71%	5.13%	34.59%	25.48%	6.16%	2.85%	0.09%	1.21%
2	Peaking Plant Capacity	D10S	100.00%	34.85%	65.15%	3.72%	61.42%	45.50%	11.78%	3.98%	0.16%	0.00%
3	57% Dmd; 43% Energy: Sales &	D57E43	100.00%	32.64%	67.19%	3.57%	63.62%	46.51%	12.05%	4.89%	0.17%	0.17%
4	40% Dmd; 60% Energy: CIP	D40E60	100.00%	31.52%	68.23%	3.49%	64.73%	47.03%	12.18%	5.35%	0.18%	0.25%
5	20%D10T; 80%D60Sub	T20D80	100.00%	37.94%	61.48%	3.53%	57.95%	43.00%	10.97%	3.95%	0.03%	0.57%
6	Labor w/o (or w/) A&G	LABOR	100.00%	36.85%	62.33%	3.94%	58.39%	42.89%	10.67%	4.68%	0.15%	0.82%
7	Net Plant In Service	NEPIS	100.00%	40.29%	58.99%	3.82%	55.17%	40.90%	9.89%	4.25%	0.13%	0.72%
8	Dis O&M w/o Sup & Misc	OXDTS	100.00%	59.59%	33.88%	4.54%	29.34%	24.32%	3.99%	1.03%	0.00%	6.52%
9	O&M w/o Reg Ex & OXTS-Alloc'	OXTS	100.00%	33.46%	65.91%	3.64%	62.26%	45.37%	11.54%	5.19%	0.17%	0.63%
10	Production Plant	P10	100.00%	30.66%	69.02%	3.43%	65.59%	47.42%	12.29%	5.70%	0.18%	0.32%
11	Production Plant Wo Nuclear	P10WoN	100.00%	31.06%	68.65%	3.46%	65.20%	47.24%	12.24%	5.54%	0.18%	0.29%
12	Total P51 & P61A	P5161A	100.00%	31.01%	68.70%	3.46%	65.24%	47.26%	12.24%	5.56%	0.18%	0.29%
13	Distribution Plant	P60	100.00%	64.73%	31.93%	4.67%	27.26%	22.85%	3.16%	1.26%	0.00%	3.34%
14	Distr Substn Plant	P61	100.00%	37.72%	61.69%	3.41%	58.28%	41.31%	10.47%	6.49%	0.00%	0.59%
15	Line Transformer Plant	P68	100.00%	65.17%	34.45%	5.07%	29.38%	28.71%	0.67%	0.00%	0.00%	0.39%
16	Services Plant	P69	100.00%	88.35%	11.65%	3.34%	8.30%	8.30%	0.00%	0.00%	0.00%	0.00%
17	Dist Plt Overhead Lines	POL	100.00%	63.36%	30.73%	4.35%	26.37%	22.97%	3.40%	0.00%	0.00%	5.91%
18	Real Est & Property Tax	PT0	100.00%	41.44%	57.44%	3.85%	53.59%	39.85%	9.53%	4.08%	0.12%	1.12%
19	Produc, Trans & Distrib	PTD	100.00%	38.79%	60.27%	3.75%	56.53%	41.68%	10.19%	4.52%	0.14%	0.94%
20	Dist Plt Undground Lines	PUL	100.00%	77.70%	21.94%	5.37%	16.56%	15.78%	0.79%	0.00%	0.00%	0.36%
21	Rate Base (Non-Column)	RTBASE	100.00%	39.38%	59.87%	3.78%	56.10%	41.47%	10.11%	4.38%	0.14%	0.75%
22	Stratified Hydro Baseload	STRATH	100.00%	30.03%	69.60%	3.39%	66.22%	47.71%	12.36%	5.96%	0.19%	0.36%
23	Transmission & Distrib	TD	100.00%	52.47%	45.55%	4.28%	41.27%	32.03%	6.66%	2.52%	0.07%	1.98%
24	Labor Dis w/o Sup & Eng	ZDTS	100.00%	55.52%	40.47%	5.01%	35.46%	28.85%	4.87%	1.71%	0.03%	4.01%

			1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
INTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
25	Labor w/o A&G	LABOR(S)	322,782	118,942	201,191	12,710	188,481	138,445	34,444	15,109	483	2,649
26	Dis O&M w/o Sup, Cust Install &	OXDTS	78,416	46,730	26,569	3,562	23,007	19,071	3,126	807	4	5,116
27	O&M w/o Reg Ex & OXTS-Alloc'	OXTS	2,407,418	805,606	1,586,682	87,737	1,498,945	1,092,210	277,729	124,939	4,067	15,130
28	Total P51 & P61A	P5161A	66,121	20,505	45,424	2,285	43,139	31,249	8,096	3,676	119	192
29	Produc, Trans & Distrib	PTD	13,710,159	5,318,095	8,263,482	513,616	7,749,865	5,714,895	1,396,768	619,210	18,992	128,583
30	Transmission & Distrib	TD	5,110,249	2,681,197	2,327,747	218,493	2,109,254	1,636,844	340,253	128,788	3,369	101,306
31	Labor Dis w/o Sup & Eng, Cust I	ZDTS	37,466	20,800	15,164	1,877	13,287	10,810	1,826	641	11	1,502

			1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
EXTERNAL ALLOCATORS		Extern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Customers - Ave Monthly	C11	100.00%	87.48%	10.41%	6.82%	3.59%	3.55%	0.04%	0.00%	0.00%	2.11%
2	Cust Acctg Wtg Factor	C11WA	100.00%	82.46%	16.91%	9.64%	7.27%	7.15%	0.11%	0.01%	0.00%	0.62%
3	Mo Cus Wtd By Mtr Invest	C12WM	100.00%	67.87%	31.94%	10.91%	21.03%	18.91%	1.92%	0.16%	0.04%	0.19%
4	Sec & Pri Customers	C61PS	100.00%	89.06%	10.61%	6.95%	3.66%	3.62%	0.04%	0.00%	0.00%	0.33%
5	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	100.00%	95.21%	4.54%	3.91%	0.63%	0.62%	0.00%	0.00%	0.00%	0.25%
6	C62Sec, w/o Ltg & C/I Undergrc	C62NL	100.00%	94.41%	5.59%	3.67%	1.91%	1.91%	0.00%	0.00%	0.00%	0.00%
7	Secondary Customers	C62Sec	100.00%	89.10%	10.57%	6.95%	3.62%	3.62%	0.00%	0.00%	0.00%	0.33%
8	Summer Peak Resp KW	D10S	100.00%	34.85%	65.15%	3.72%	61.42%	45.50%	11.78%	3.98%	0.16%	0.00%
9	Transmission Demand %	D10T	100.00%	34.09%	65.50%	3.60%	61.90%	45.21%	11.74%	4.77%	0.17%	0.41%
10	Winter Peak Resp KW	D10W	100.00%	33.05%	65.97%	3.43%	62.54%	44.81%	11.68%	5.85%	0.19%	0.98%
11	Alternative Production Allocator	1CP	100.00%	34.85%	65.15%	3.72%	61.42%	45.50%	11.78%	3.98%	0.16%	0.00%
12	Sec, Pri & TT, Class Coin kW @	D60Sub	100.00%	38.91%	60.48%	3.51%	56.97%	42.45%	10.77%	3.75%	0.00%	0.62%
13	Sec & Pri, Cl Coin kW (no Min S	D61PS	100.00%	35.16%	64.34%	3.09%	61.26%	48.75%	12.51%	0.00%	0.00%	0.50%
14	Pri & Sec Coin kW Served w/ 1 F	D61PS1Ph	100.00%	76.44%	22.80%	3.53%	19.27%	17.08%	2.19%	0.00%	0.00%	0.76%
15	D62Sec, w/o Ltg & C/I Undergrc	D62NLL	100.00%	72.25%	27.75%	2.47%	25.28%	25.28%	0.00%	0.00%	0.00%	0.00%
16	Sec, Class Coin kW (w/o Min Sy	D62SecL	100.00%	48.26%	51.32%	3.70%	47.62%	47.62%	0.00%	0.00%	0.00%	0.42%
17	Direct Assign Street Lighting	DASL	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
18	On + Off Sales MWH	E8760	100.00%	29.24%	70.34%	3.33%	67.01%	48.07%	12.46%	6.29%	0.19%	0.43%
19	Street Lighting (Dir Assign)	P73	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
20	MWh Sales Excl CIP Exempt	E99XCIP	100.00%	30.230%	69.17%	3.34%	65.829%	50.72%	11.88%	3.02%	0.21%	0.60%
21	Present Rev	R01	100.00%	36.20%	62.87%	3.82%	59.05%	44.26%	10.04%	4.58%	0.16%	0.93%
22	Rate Discount Allocator	DiscAlloc	100.00%	34.88%	65.10%	3.72%	61.38%	45.48%	11.75%	3.99%	0.16%	0.02%

			1=2+3+10	2	3=4+5	4	5	6	7	8	9	10
EXTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
23	Customers - B Basis	C10	1,246,729	1,110,368	132,278	86,636	45,642	45,146	469	17	10	4,082
24	Cust - Ave Monthly (C10-Area Lt	C11	1,272,915	1,113,587	132,467	86,824	45,642	45,146	469	17	10	26,861
25	Mo Cus Wtd By Cus Acct	C11WA	1,348,405	1,111,962	228,042	130,047	97,994	96,363	1,513	76	43	8,401
26	Cust Acctg Wtg Factor	C11WAF	16.53	1.00	15.53	1.50	14.03	2.13	3.23	4.33	4.33	N/A
27	Cust-Ave Mo (C11 w/ Dir Assign	C12	1,247,752	1,113,587	132,467	86,824	45,642	45,146	469	17	10	1,698
28	Mo Cus Wtd By Mtr Invest	C12WM	139,013,836	94,348,476	44,403,548	15,171,232	29,232,317	26,286,769	2,663,081	222,840	59,626	261,811
29	Meter Invest / Cust Factor	C12WMF	25,496	85	25,257	175	25,082	582	5,683	12,749	6,067	154
30	Sec & Pri Customers	C61PS	1,246,702	1,110,368	132,251	86,636	45,615	45,146	469	0	0	4,082
31	% Served by Primary Single Phase		0.0%	74.5%	0.0%	39.2%	0.0%	12.0%	6.0%	0.0%	0.0%	52.3%
32	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	868,249	826,678	39,436	33,989	5,446	5,418	28	0	0	2,136
33	C62Sec, w/o Ltg & C/I Undergrc	C62NL	1,176,054	1,110,368	65,686	43,183	22,503	22,503	0	0	0	0
34	Secondary Customers	C62Sec	1,246,233	1,110,368	131,782	86,636	45,146	45,146	0	0	0	4,082
35	Summer Peak Resp KW	D10S	7,228	2,519	4,709	269	4,440	3,289	852	288	12	0
36	Dmd (D10S x Fact + D10W)/100	D10T	10,000,000	3,408,887	6,549,694	360,008	6,189,685	4,520,889	1,174,142	477,214	17,440	41,419
37	Winter Peak Resp KW	D10W	4,377	1,447	2,888	150	2,737	1,961	511	256	9	43
38	Alternative Production Allocator	1CP	7,228	2,519	4,709	269	4,440	3,289	852	288	12	0
39	Sec, Pri & TT, Class Coin kW @	D60Sub	7,906,068	3,075,858	4,781,578	277,549	4,504,029	3,356,061	851,693	296,275	0	48,632
40	Sec & Pri, Class Coin kW (w/o M	D61PS	6,789,272	2,387,380	4,368,238	209,462	4,158,776	3,309,455	849,320	0	0	33,654
41	Pri & Sec Coin kW Served w/ 1 F	D61PS1Ph	2,325,277	1,777,423	530,245	82,177	448,068	397,179	50,889	0	0	17,610
42	D62Sec, w/o Ltg & C/I Undergrc	D62NLL	9,292,559	6,713,761	2,578,797	229,922	2,348,875	2,348,875	0	0	0	0
43	Sec, Class Coin kW (w/o Min Sy	D62SecL	10,000,000	4,825,623	5,132,146	369,797	4,762,349	4,762,349	0	0	0	42,230
44	Annual Billing kW	D99	53,267.029	0	53,267	0	53,267	40,424	8,518	4,077	248	0
45	Summer Billing kW	D99S	19,423.061	0	19,423	0	19,423	14,775	3,164	1,392	91	0
46	Winter Billing kW	D99W	33,843.967	0	33,844	0	33,844	25,648	5,354	2,685	157	0
47	Non-Coinc Pk Second	DN-Sec	11,920,622	6,713,761	5,173,718	461,282	4,712,436	4,712,436	0	0	0	33,143
48	MWh Sales	E99	30,773,808	8,756,626	21,843,303	968,021	20,875,282	14,759,156	3,939,474	2,115,136	61,516	173,879
49	MWh Sales Excl CIP Exempt	E99XCIP	28,966,877	8,756,626	20,036,388	967,847	19,068,541	14,692,304	3,440,811	873,910	61,516	173,864

PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED
– PUBLIC DATA –

☐ **Non Public Document – Contains Trade Secret Data**
☒ **Public Document – Trade Secret Data Excised**
☐ **Public Document**

Xcel Energy			
Docket No.:	E002/GR-13-868		
Response To:	Department of Commerce	Information Request No.	4
Requestor:	Samir Quanes/Sachin Shah/Dale Lusti/Nancy Campbell/Sue Peirce		
Date Received:	May 14, 2015		**SUPPLEMENT REVISED**

Question:

Subject: Commission-required revised 2014 CCOSS and Apportionment

In its May 8, 2015 Order at 84 in Docket No. E002/GR-13-868, the Commission required that "the Company rerun its CCOSS with modifications required by this order [2015 Order], and calculate the apportionment based on that revised CCOSS."

1) Please provide a hard copy and an electronic copy (Excel spreadsheet) of the Commission-required revised 2014 CCOSS discussed above with all links and formulas intact.

2) Please provide a list of all modifications to the inputs of Xcel's Direct 2014 CCOSS required by the 2015 Order.

3) Please provide a list of all modifications Xcel made to the inputs of Xcel's Direct 2014 CCOSS in response to question 1 above.

4) Please provide a side-by-side comparison of the required modifications and the modifications made to the inputs of Xcel's Direct 2014 CCOSS in response to questions 2 and 3 above.

5) Please explain and justify any difference between the lists provided in response to question 2 and 3 above.

PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED
– PUBLIC DATA –

6) Please provide a list of all modifications to the classification and allocation methods of Xcel's Direct 2014 CCOSS required by the 2015 Order.

7) Please provide a list of all modifications Xcel made to Xcel's Direct 2014 CCOSS classification and allocation methods in response to question 1.

8) Please provide a side-by-side comparison of the required modifications and the modifications made to the classification and allocation methods of Xcel's Direct 2014 CCOSS in response to questions 6 and 7 above.

9) Please explain and justify any difference between the lists provided in response to question 6 and 7 above.

10) Please demonstrate that the revised 2014 CCOSS provided in response to question 1 above incorporates all the modifications required by the 2015 Order.

11) Please calculate the apportionment based on the revised 2014 CCOSS provided in response to question 1 above.

12) Please demonstrate that your calculation of the apportionment in response to question 11 above is in compliance with the Commission required apportionment at page 84 of the 2015 Order.

Response:

1) The trade secret electronic version of the 2014 Class Cost of Service Study "MN CCOSS 2014 Compliance as filed.zip" was previously provided to Department staff on May 5, 2015 and has not changed. Included with this response is Attachment A, provided in live Excel format, which is a summary of the CCOSS results and Attachment B to this response, also provided in live Excel formal, which shows detailed CCOSS results.

2) The following financial input modifications are required by the Commissions 2015 order:

   a. Update the capital structure to the Commission ordered rate of return.

   b. Update the MN jurisdiction rate base and expense inputs to the Commission ordered amounts to reflect the ordered revenue requirement and associated deficiency.

PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED
– PUBLIC DATA –

c. Update present revenues, sales and customers to reflect 2014 weather normalized actual values.

d. Recover CIP costs through base rates rather than recovering them entirely via the rider

3) The modifications listed in the response to item 2 above are the only ones that were made to the CCOSS.

4) Please see the response to items 2 and 3.

5) Please see the response to items 2 and 3.

6) Below is a list of all modifications to the classification and allocation methods required by the 2015 Commission Order:

a. Adjust the energy, demand and customer allocators to reflect the change sales and customers.

b. Use the "location method" for classifying other production O&M costs into capacity and energy-related components. Capacity-related costs are allocated to customer class with the Commission approved D10S allocator while energy-related costs are allocated with the approved E8760 allocator.

c. Use 2013 cost data for stratifying Pleasant Valley and Border Winds as well as all other production plant costs.

Commission Order Point IV. B. 4. a), as adopted by the Commission, states the following:

> *"Adopt the ALJ's finding and recommendation and require Xcel to update its CCOSS results using 2013 cost data for Pleasant Valley and Border Winds as well as for all production plant costs in its plant stratification analysis."*

d. Classify the cost of the Grand Meadow and Nobles wind farms on the same basis as its other fixed production plant costs using the plant stratification method.

**PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED
– PUBLIC DATA –**

e. Adopt the revised economic development amounts that were included in the Company's CCOSS that was filed in Rebuttal testimony and allocate these costs to class based on Present Revenue.

7) The modifications listed in the response to item 6 are the only ones that were made to the CCOSS.

8) Please see the responses to items 6 and 7.

9) Please see the response to items 6 and 7.

10) Referencing the response to item 2 above, below is the list of modifications to the CCOSS financial inputs required by the 2015 Commission order and an indication where these modifications are demonstrated.

a. Update the capital structure to the Commission ordered rate of return.

The capital structure has been updated to the Commission ordered Return on Equity of 9.72% and the Rate of Return of 7.34%. This is shown on the trade secret live version of the 2014 compliance CCOSS on the spreadsheet tab labeled "JCOSS" on spreadsheet rows 45 to 51.

b. Update the MN jurisdiction rate base and expense inputs to the Commission ordered amounts to reflect the Commission's ordered revenue requirement and associated deficiency.

Column 1; Row 15 of Attachment A to this response, which is a summary of 2014 Compliance CCOSS results, shows that the 2014 deficiency is $58,908,000. This deficiency matches the deficiency as shown in the Company's April 24th compliance filing – Preliminary Financial Schedules as shown on Schedule A1; Page 3 of 3; Column 1; Row 10.

A selected line item comparison of Commission approved rate base amounts as shown on Schedule A4 of Company's April 24th compliance filing – Preliminary Financial Schedules to the Company's 2014 Compliance CCOSS as provided in Attachment B to this response is shown in the table below:

PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED
– PUBLIC DATA –

Rate Base Amount	Commission Approved Amount from Schedule A4	2014 Compliance CCOSS Reference in DOC-0004_Att B.xlsx
Utility Plant in Service	Column 12; Line 6	Page 4; Column 1; Line 52
Depreciation Reserve	Column 12; Line 12	Page 5; Column 1; Line 28
Total Average Rate Base	Column 12; Line 35	Page 6; Column 1; Line 36

A selected line item comparison of Commission approved revenue and expense amounts as shown on Schedule A5, page 3 of 3 of Company's April 24th compliance filing – Preliminary Financial Schedules to the Company's 2014 Compliance CCOSS as Attachment B to this response is shown below:

Revenue or Expense Amount	Commission Approved Amount from Schedule A5 ; Page 3 of 3	2014 Compliance CCOSS Reference in DOC-0004_Att B.xlsx
Total Operating Revenue	Column 34; Line 4	Page 7; Column 1; Line 27
Federal and State Income Taxes	Column 34; Line 18	Page 11; Column 1; Line 39A
Total Expenses	Column 34; Line 21	Page 10; Column 1; Line 48 **PLUS** Page 11; Column 1; Line 39A

c. Update present revenues, sales and customers to reflect 2014 weather normalized actual values.

Column 2 of Tables 1-3 below show the updates that were made to reflect 2014 weather normalized actual values.

Table 1

2014 Present Revenues ($000)				
	[1]	[2]	[3]	[4]
Customer Class	**Direct CCOSS**	**Compliance CCOSS**	**Change**	**% Change**
Residential	$1,001,398	$1,023,121	$21,723	2.169%
Commercial Non Demand	$105,523	$108,086	$2,563	2.429%
C&I Demand	$1,655,347	$1,669,134	$13,787	0.833%
Lighting	$26,477	$26,319	-$158	-0.597%
Total	$2,788,745	$2,826,661	$37,916	1.360%

PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED
– PUBLIC DATA –

Table 2

2014 MWh Sales				
	[1]	[2]	[3]	[4]
Customer Class	**2014 Direct**	**2014 Compliance**	**Change**	**% Change**
Residential	8,507,873	8,756,626	248,753	2.924%
Commercial Non Demand	937,895	968,021	30,125	3.212%
C&I Demand	20,614,915	20,859,682	244,767	1.187%
Lighting	174,524	173,879	-645	-0.370%
Total	30,235,207	30,758,208	523,000	1.730%

Table 3

2014 Customer Counts				
	[1]	[2]	[3]	[4]
Customer Class	**2014 Direct**	**2014 Compliance**	**Change**	**% Change**
Residential	1,108,321	1,113,587	5,266	0.475%
Commercial Non Demand	86,595	86,824	229	0.265%
C&I Demand	45,534	45,642	108	0.237%
Lighting	27,277	26,861	-415	-1.523%
Total	1,267,726	1,272,915	5,188	0.409%

Updated present revenues are shown on rows 4 and 14 of Attachment A. Updated MWh sales for 2014 are shown on page 2, line 21 of Attachment B while updated customer counts are shown on page 2, line 14 of the same attached file.

d. CIP costs are included in base rates as shown on Page 8; Column 1; Line 30 of Attachment B.

Referencing the response to item 6 above, below is the list of modifications to the classification and allocation methods required by the 2015 Commission order and an indication where these modifications are demonstrated.

i. Each customer classes' hourly load data that is used to calculate the demand and energy allocators was adjusted to reflect the change in sales levels as shown in column 4 of Table 2 above. The customer allocators were adjusted to those shown in column 2 of Table 3 above. The adjusted class allocation data is shown on page 14 lines 23-49 of

PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED
– PUBLIC DATA –

Attachment B. The resulting class cost allocation factors are shown on page 14, lines 1-22 of the same Attachment B.

ii. As shown on Page 24, lines 11 – 13 of Michael Peppin's direct testimony, using the "Location Method", the capacity versus energy split for Other Production O&M expenses is 35.0% capacity-related versus 65.0% energy-related. Page 7, Column 1, Lines 39-41 of Attachment B shows the following classification of Other Production O&M costs:

Other Production O&M	($000)	Percent
Capacity-Related	$174,989	35.0%
Energy-Related	$325,323	65.0%
Total Other Production	$500,312	100.0%

Capacity-related costs are allocated to class using the Commission approved D10S allocator, while energy-related costs are allocated to class using the approved E78760 allocator.

iii. The Commission ordered updated plant stratification costs are shown in Column 4 of Table 4 below. Columns 2 and 3 show the plant stratification percentages that were applied in the direct testimony CCOSS, while Columns 5 and 6 shows the updated percentages that were applied in the Compliance CCOSS.

Table 4

Plant Type	Direct Testimony CCOSS			Compliance CCOSS		
	[1]	[2]	[3]	[4]	[5]	[6]
	Peaking Ratio	Peaking %	Baseload %	Peaking Ratio	Peaking %	Baseload %
Nuclear	$770 / $3,689	20.9%	79.1%	$792 / $4,146	19.1%	80.9%
Fossil	$770 / $1,976	39.0%	61.0%	$792 / $2,022	39.2%	60.8%
Combined Cycle	$770 / $1,020	75.4%	24.6%	$792 / $1,037	76.3%	23.7%
Hydro	$770 / $4,519	17.0%	83.0%	$792 / $5,601	14.1%	85.9%
Grand Meadow & Nobles	Not Applicable	100%	0%	$792 / $18,142	4.4%	95.6%
Pleasant Valley	$770 /	4.5%	95.5%	$792 /	6.7%	93.3%

PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED
– PUBLIC DATA –

Plant Type	Direct Testimony CCOSS			Compliance CCOSS		
	[1]	[2]	[3]	[4]	[5]	[6]
	Peaking Ratio	Peaking %	Baseload %	Peaking Ratio	Peaking %	Baseload %
& Border Winds	$17,150			$11,761		

The updated plant stratification results are applied to the following inputs to the CCOSS so as to separate these costs into baseload and peaking components.

- Plant in service
- Depreciation reserve
- Accumulated deferred income tax
- Construction work in progress
- Book depreciation
- Provision for deferred income taxes
- Investment tax credit
- Tax depreciation and removal expense
- AFUDC

Capacity-related costs are allocated to class using the Commission approved D10S allocator, while energy-related costs are allocated to class using the approved E78760 allocator.

iv. Columns 5 and 6 of Table 4 above shows the Peaking/Baseload plant stratification percentages that were applied to Grand Meadow and Nobles costs in the Company's Compliance CCOSS.

v. In the CCOSS filed with the Company's compliance filing and shown in Attachments A and B, the rate discounts for economic development were inadvertently excluded from the rate discount cost allocation process. The corrected trade secret cost allocation process is shown below:

PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED
– PUBLIC DATA –

	MN	Residential	Commercial Non Demand	C&I Demand	St Ltg
D10S Allocator	100.00%	34.85%	3.72%	61.42%	0.00%
Present Revenue Allocator	100.00%	36.21%	3.83%	59.04%	0.93%
	[Trade Secret Data Begins…				
Interruptible Rate Discounts Allocated					
Economic Development Discounts Allocated					
Total Allocated Discounts					

…Trade Secret Data Ends]

In the corrected CCOSS, the adjusted revenue deficiency would change as shown below

	MN	Residential	Commercial Non Demand	C&I Demand	Lighting
Corrected Adjusted Revenue Deficiency	58,908	25,334	1,663	33,952	-2,041
Adjusted Revenue Deficiency as Filed	58,908	24,865	1,613	34,471	-2,041
Difference	0	469	50	-519	0

11) Please see Attachment C to this response which shows the ordered class revenue apportionment.

12) The Commercial class cost (column B) equals ordered apportionment (column K). The Residential apportionment is 75 percent of the difference between present revenue factored to the ordered level (column E) and cost (column B), as shown in Column J, with the ordered class apportionment representing the total of Columns E and J. The Lighting class revenue apportionment remains at present revenue as ordered. The Demand class revenue apportionment represents the remainder of the ordered retail revenue requirement.

Portions of this response are marked "Non-Public" as it contains information the Company considers to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). The information derives independent economic value from not being generally

PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED
– PUBLIC DATA –

known or readily ascertainable by others who could obtain a financial advantage from their use. Thus, Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500.

Supplemental Response:

10) In a meeting on Thursday, May 21, the Department of Commerce requested we isolate selected sample adjustments for the 2014 Test Year to further demonstrate that the revised 2014 CCOSS provided in response to question 1 incorporates all the modifications required by the 2015 Order.

Per the Department's request, Attachment D to this response provides CCOSS inputs from the Jurisdictional Cost of Service, isolated by the following individual revenue requirement adjustments:

- Monticello EPU 50/50 Used & Useful
- Commission Aviation
- PI EPU Debt Return Only

The subtotals in Attachment D match the amounts for each adjustment in Schedules A4 and A5 of the Preliminary Compliance filed April 24, 2015.

Attachment D, in live Excel spreadsheet format has been marked "Non-Public" in its entirety. Attachment D is a CCOSS model excerpt and is protected by the Minnesota Data Practices Act. The model has economic value (actual or potential) to the Company as a result of not being generally known to, and not being readily ascertainable by proper means, by other persons. The Company takes efforts to protect the model from public disclosure. Xcel Energy maintains this model as a trade secret based on the economic value associated with the model not being generally known by other persons who can obtain economic value from its disclosure or use and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. For this reason, we ask Non-Public Attachment D be treated as non-public data pursuant to Minn. Stat. § 13.37, subd. 1(b).

Revision:

Please note that the "Total Allocated Discounts" row at the top of Page 9 of the supplemented version of this response should have been marked as Trade Secret. The correction has been made in the table in this supplemented, revised version.

PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED
– PUBLIC DATA –

Preparer: Michael Peppin / Steve Huso / Chuck Burdick
Title: Principal Pricing Analyst / Pricing Consultant / Principal Rate Analyst
Department: Regulatory Analysis / Revenue Requirements North
Telephone: 612-337-2317 / 612-330-2944 / 612-330-6646
Date: May 27, 2015 Supplemented: May 28, 2015
Supplement Revised: June 8, 2015

PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED
– PUBLIC DATA –

☐ **Non Public Document – Contains Trade Secret Data**
☒ **Public Document – Trade Secret Data Excised**
☐ **Public Document**

Xcel Energy
Docket No.: E002/GR-13-868
Response To: Department of Commerce Information Request No. 5
Requestor: Samir Quanes/Sachin Shah/Dale Lusti/Nancy Campbell/Sue Peirce
Date Received: May 14, 2015 **SUPPLEMENT REVISED**

Question:

Subject: Commission-required revised 2015 CCOSS and Apportionment

In its May 8, 2015 Order at 84 in Docket No. E002/GR-13-868, the Commission required that "the Company rerun its CCOSS with modifications required by this order [2015 Order], and calculate the apportionment based on that revised CCOSS."

1) Please provide a hard copy and an electronic copy (Excel spreadsheet) of the Commission-required revised 2015 CCOSS discussed above with all links and formulas intact.

2) Please provide a list of all modifications to the inputs of Xcel's Direct 2015 CCOSS required by the 2015 Order.

3) Please provide a list of all modifications Xcel made to the inputs of Xcel's Direct 2015 CCOSS in response to question 1 above.

4) Please provide a side-by-side comparison of the required modifications and the modifications made to the inputs of Xcel's Direct 2015 CCOSS in response to questions 2 and 3 above.

5) Please explain and justify any difference between the lists provided in response to question 2 and 3 above.

6) Please provide a list of all modifications to the classification and allocation methods of Xcel's Direct 2015 CCOSS required by the 2015 Order.

PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED
– PUBLIC DATA –

7) Please provide a list of all modifications Xcel made to Xcel's Direct 2015 CCOSS classification and allocation methods in response to question 1.

8) Please provide a side-by-side comparison of the required modifications and the modifications made to the classification and allocation methods of Xcel's Direct 2015 CCOSS in response to questions 6 and 7 above.

9) Please explain and justify any difference between the lists provided in response to question 6 and 7 above.

10) Please demonstrate that the revised 2015 CCOSS provided in response to question 1 above incorporates all the modifications required by the 2015 Order.

11) Please calculate the apportionment based on the revised 2015 CCOSS provided in response to question 1 above.

12) Please demonstrate that your calculation of the apportionment in response to question 11 above is in compliance with the Commission required apportionment at page 84 of the 2015 Order.

<u>Response</u>:

1) The trade secret electronic version of the 2015 Class Cost of Service Study "MN CCOSS 2015 Compliance as filed.zip" was previously provided to Department staff on May 5, 2015 and has not changed. Included with this response is Attachment A, provided in live Excel format, which is a summary of the CCOSS results and Attachment B to this response, also provided in live Excel formal, which shows detailed CCOSS results.

2) The following financial input modifications are required by the Commissions 2015 order:

    a. Update the capital structure to the Commission ordered rate of return.

    b. Update the MN jurisdiction rate base and expense inputs to the Commission ordered amounts to reflect the ordered revenue requirement and associated deficiency.

PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED
– PUBLIC DATA –

c. Update present revenues, sales and customers to reflect 2014 weather normalized actual values.

d. Recover CIP costs through base rates rather than recovering them entirely via the rider

3) The modifications listed in the response to item 2 above are the only ones that were made to the CCOSS.

4) Please see the response to items 2 and 3.

5) Please see the response to items 2 and 3.

6) Below is a list of all modifications to the classification and allocation methods required by the 2015 Commission Order:

a. Adjust the energy, demand and customer allocators to reflect the change sales and customers.

b. Use the "location method" for classifying other production O&M costs into capacity and energy-related components. Capacity-related costs are allocated to customer class with the Commission approved D10S allocator while energy-related costs are allocated with the approved E8760 allocator.

c. Use 2013 cost data for stratifying Pleasant Valley and Border Winds as well as all other production plant costs.

Commission Order Point IV. B. 4. a), as adopted by the Commission, states the following:

> *"Adopt the ALJ's finding and recommendation and require Xcel to update its CCOSS results using 2013 cost data for Pleasant Valley and Border Winds as well as for all production plant costs in its plant stratification analysis."*

d. Classify the cost of the Grand Meadow and Nobles wind farms on the same basis as its other fixed production plant costs using the plant stratification method.

PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED
– PUBLIC DATA –

e. Adopt the revised economic development amounts that were included in the Company's CCOSS that was filed in Rebuttal testimony and allocate these costs to class based on Present Revenue.

7) The modifications listed in the response to item 6 are the only ones that were made to the CCOSS.

8) Please see the responses to items 6 and 7.

9) Please see the response to items 6 and 7.

10) Referencing the response to item 2 above, below is the list of modifications to the CCOSS financial inputs required by the 2015 Commission order and an indication where these modifications are demonstrated.

a. Update the capital structure to the Commission ordered rate of return.

The capital structure has been updated to the Commission ordered Return on Equity of 9.72% and the Rate of Return of 7.37%. This is shown on the attached trade secret live version of the 2015 compliance CCOSS on the spreadsheet tab labeled "JCOSS" on spreadsheet rows 45 to 51.

b. Update the MN jurisdiction rate base and expense inputs to the Commission ordered amounts to reflect the Commission's ordered revenue requirement and associated deficiency.

Column 1; Row 15 of Attachment A, which is a summary of 2015 Compliance CCOSS results, shows that the 2015 deficiency is $168,085,000. This deficiency matches the deficiency as shown in the Company's April 24th compliance filing – Preliminary Financial Schedules as shown on Schedule A1; Page 3 of 3; Column 3; Row 10.

A selected line item comparison of Commission approved rate base amounts as shown on Schedule A4 of Company's April 24th compliance filing – Preliminary Financial Schedules to the Company's 2015 Compliance CCOSS as Attachment B is shown below:

PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED
– PUBLIC DATA –

Rate Base Amount	Commission Approved Amount from Schedule A6; Page 2 of 2	2015 Compliance CCOSS Reference in DOC-0005_Att B.xlsx
Utility Plant in Service	Column 3; Line 6	Page 4; Column 1; Line 52
Depreciation Reserve	Column 3; Line 12	Page 5; Column 1; Line 28
Total Average Rate Base	Column 3; Line 35	Page 6; Column 1; Line 36

A selected line item comparison of Commission approved revenue and expense amounts as shown on the Attachment C to this response as compared to the Company's 2015 Compliance CCOSS which is Attachment B to this response and is shown below as follows:

Revenue or Expense Amount	DOC-0005_Att C: Income Statement Combined 2014 TY and 2015 Step	2015 Compliance CCOSS Reference in DOC-0005_Att B.xlsx
Total Operating Revenue	Column 3; Line 4	Page 7; Column 1; Line 27
Federal and State Income Taxes	Column 3; Line 18	Page 11; Column 1; Line 39A
Total Expenses	Column 3; Line 21	Page 10; Column 1; Line 48 **PLUS** Page 11; Column 1; Line 39A

c. Update present revenues, sales and customers to reflect 2014 weather normalized actual values.

Column 2 of Tables 1-3 below show the updates that were made to reflect 2014 weather normalized actual values.

Table 1

2014 Present Revenues ($000)				
	[1]	[2]	[3]	[4]
Customer Class	**Direct CCOSS**	**Compliance CCOSS**	**Change**	**% Change**
Residential	$1,001,398	$1,023,121	$21,723	2.169%
Commercial Non Demand	$105,523	$108,086	$2,563	2.429%
C&I Demand	$1,655,347	$1,669,134	$13,787	0.833%
Lighting	$26,477	$26,319	-$158	-0.597%
Total	$2,788,745	$2,826,661	$37,916	1.360%

Table 2

PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED
– PUBLIC DATA –

2014 MWh Sales				
	[1]	[2]	[3]	[4]
Customer Class	**2014 Direct**	**2014 Compliance**	**Change**	**% Change**
Residential	8,507,873	8,756,626	248,753	2.924%
Commercial Non Demand	937,895	968,021	30,125	3.212%
C&I Demand	20,614,915	20,859,682	244,767	1.187%
Lighting	174,524	173,879	-645	-0.370%
Total	30,235,207	30,758,208	523,000	1.730%

Table 3

2014 Customer Counts				
	[1]	[2]	[3]	[4]
Customer Class	**2014 Direct**	**2014 Compliance**	**Change**	**% Change**
Residential	1,108,321	1,113,587	5,266	0.475%
Commercial Non Demand	86,595	86,824	229	0.265%
C&I Demand	45,534	45,642	108	0.237%
Lighting	27,277	26,861	-415	-1.523%
Total	1,267,726	1,272,915	5,188	0.409%

Updated present revenues are shown on rows 4 and 14 of Attachment A. Updated MWh sales for 2014 are shown on page 2, line 21 of Attachment B, while updated customer counts are shown on page 2, line 14 of the same attached file.

d. CIP costs are included in base rates as shown on Page 8; Column 1; Line 30 of Attachment B.

Referencing the response to item 6 above, below is the list of modifications to the classification and allocation methods required by the 2015 Commission order and an indication where these modifications are demonstrated.

i. Each customer classes' hourly load data that is used to calculate the demand and energy allocators was adjusted to reflect the change in sales levels as shown in column 4 of Table 2 above. The customer allocators were adjusted to those shown in column 2 of Table 3 above. The adjusted class allocation data is shown on page 14 lines 23-49 of Attachment B. The resulting class cost allocation factors are shown on page 14, lines 1-22 of the same attachment.

PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED
– PUBLIC DATA –

ii. As shown on Page 24, lines 11 – 13 of Michael Peppin's direct testimony, using the "Location Method", the capacity versus energy split for Other Production O&M expenses is 35.0% capacity-related versus 65.0% energy-related. Page 7, Column 1, Lines 39-41 of Attachment B shows the following classification of Other Production O&M costs:

Other Production O&M	($000)	Percent
Capacity-Related	$176,520	35.0%
Energy-Related	$328,170	65.0%
Total Other Production	$504,691	100.0%

Capacity-related costs are allocated to class using the Commission approved D10S allocator, while energy-related costs are allocated to class using the approved E78760 allocator.

iii. The Commission ordered updated plant stratification costs are shown in Column 4 of Table 4 below. Columns 2 and 3 show the plant stratification percentages that were applied in the direct testimony CCOSS, while Columns 5 and 6 shows the updated percentages that were applied in the Compliance CCOSS.

Table 4

Plant Type	Direct Testimony CCOSS			Compliance CCOSS		
	[1]	[2]	[3]	[4]	[5]	[6]
	Peaking Ratio	Peaking %	Baseload %	Peaking Ratio	Peaking %	Baseload %
Nuclear	$770 / $3,689	20.9%	79.1%	$792 / $4,146	19.1%	80.9%
Fossil	$770 / $1,976	39.0%	61.0%	$792 / $2,022	39.2%	60.8%
Combined Cycle	$770 / $1,020	75.4%	24.6%	$792 / $1,037	76.3%	23.7%
Hydro	$770 / $4,519	17.0%	83.0%	$792 / $5,601	14.1%	85.9%
Grand Meadow & Nobles	Not Applicable	100%	0%	$792 / $18,142	4.4%	95.6%
Pleasant Valley & Border Winds	$770 / $17,150	4.5%	95.5%	$792 / $11,761	6.7%	93.3%

PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED
– PUBLIC DATA –

The updated plant stratification results are applied to the following inputs to the CCOSS so as to separate these costs into baseload and peaking components.

- Plant in service
- Depreciation reserve
- Accumulated deferred income tax
- Construction work in progress
- Book depreciation
- Provision for deferred income taxes
- Investment tax credit
- Tax depreciation and removal expense
- AFUDC

Capacity-related costs are allocated to class using the Commission approved D10S allocator, while energy-related costs are allocated to class using the approved E78760 allocator.

iv. Columns 5 and 6 of Table 4 above shows the Peaking/Baseload plant stratification percentages that were applied to Grand Meadow and Nobles costs in the Company's Compliance CCOSS.

v. In the CCOSS filed with the Company's compliance filing and shown in Attachments A and B, the rate discounts for economic development were inadvertently excluded from the rate discount cost allocation process. The corrected trade secret cost allocation process is shown below:

	MN	Residential	Commercial Non Demand	C&I Demand	St Ltg
D10S Allocator	100.00%	34.85%	3.72%	61.42%	0.00%
Present Revenue Allocator	100.00%	36.20%	3.82%	59.05%	0.93%
	[Trade Secret Data Begins…				
Interruptible Rate Discounts Allocated					
Economic Development Discounts Allocated					
Total Allocated Discounts					

…Trade Secret Data Begins]

PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED
– PUBLIC DATA –

In the corrected CCOSS, the adjusted revenue deficiency would change as shown below:

	MN	Residential	Commercial Non Demand	C&I Demand	Lighting
Corrected Adjusted Revenue Deficiency	168,085	64,941	5,579	98,095	-530
Adjusted Revenue Deficiency as Filed	168,085	64,471	5,528	98,615	-530
Difference	0	469	50	-519	0

11) Please see Attachment D to this response which shows the ordered class revenue apportionment.

12) The Commercial class cost (column B) equals ordered apportionment (column K). The Residential apportionment is 75 percent of the difference between present revenue factored to the ordered level (column E) and cost (column B), as shown in Column J, with the ordered class apportionment representing the total of Columns E and J. The Lighting class revenue apportionment remains at present revenue as ordered. The Demand class revenue apportionment represents the remainder of the ordered retail revenue requirement.

Portions of this response are marked "Non-Public" as it contains information the Company considers to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). The information derives independent economic value from not being generally known or readily ascertainable by others who could obtain a financial advantage from their use. Thus, Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500.

Supplemental Response:

10) In a meeting on Thursday, May 21, the Department of Commerce requested we isolate selected sample adjustments for the 2014 Test Year to further demonstrate that the revised 2014 CCOSS provided in response to question 1 incorporates all the modifications required by the 2015 Order.

Per the Department's request, Attachment E to this response provides CCOSS inputs from the Jurisdictional Cost of Service, isolated by the following

PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED
– PUBLIC DATA –

individual revenue requirement adjustments:

- Pleasant Valley and Border Winds PTCs
- Monticello LCM/EPU No Return

The subtotals in Attachment E match the amounts for each adjustment in Schedule A7 of the Preliminary Compliance filed April 24, 2015.

Please note that the PTC credit is absorbed in the NOL calculation (the NOL grows due to deferring the impact of the PTCs in the current year). Also note that the Cost of Service included in the April 24 filing used a revenue offset for the impact of the PTCs but they should be recorded on the Federal Tax Credit line. Lastly, the difference between $6,504,000 tax impact and the $11,093,000 revenue impact is the gross-up factor for taxes of 1.705611. This ensures the revenue requirement impact is the same in both treatments.

Attachment E, in live Excel spreadsheet format has been marked "Non-Public" in its entirety. Attachment E is a CCOSS model excerpt and is protected by the Minnesota Data Practices Act. The model has economic value (actual or potential) to the Company as a result of not being generally known to, and not being readily ascertainable by proper means, by other persons. The Company takes efforts to protect the model from public disclosure. Xcel Energy maintains this model as a trade secret based on the economic value associated with the model not being generally known by other persons who can obtain economic value from its disclosure or use and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. For this reason, we ask Non-Public Attachment E be treated as non-public data pursuant to Minn. Stat. § 13.37, subd. 1(b).

<u>Revision</u>

Please note that the "Total Allocated Discounts" row at the bottom of Page 8 of the supplemented version of this response should have been marked as Trade Secret. The correction has been made in the table in this supplemented, revised version.

PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED
– PUBLIC DATA –

Preparer:	Michael Peppin / Steve Huso / Chuck Burdick
Title:	Principal Pricing Analyst / Pricing Consultant / Principal Rate Analyst
Department:	Regulatory Analysis / Revenue Requirements North
Telephone:	612-337-2317 / 612-330-2944 / 612-330-6646
Date:	May 27, 2015 Supplemented: May 28, 2015
	Supplement Revised: June 8, 2015

PUBLIC DOCUMENT

TRADE SECRET INFORMATION AND NON-PUBLIC DATA EXCISED

Northern States Power Company | **Docket No. E002/GR-13-868**

Electric Utility - State of Minnesota | **Reply Comments - CCOSS and Revenue Apportionment Schedules**

Comparisons of Sales, Revenues, and Rate Discounts | **Attachment E - Page 1 of 1**

($s)

Retail	Interruptible Discounts	Econ Dev Credits[1]	Int Discts +ED Credits	ED Adj	Retail MWH	Present Retail Rev	Notes
Revenue	***[TRADE SECRET BEGINS***						
Filed TY2014					30,235,207	$2,788,744,835	2
Rebuttal TY2014					30,460,181	$2,713,835,595	3
Jan 2015 Compliance TY 2014					30,758,208	$2,736,274,423	4
Apr 2015 Prelim Compl TY2014					30,758,208	$2,826,038,503	5
Apr 2015 Prelim Compl TY2015					30,773,808	$2,826,660,985	6
				TRADE SECRET ENDS]			
CCOSS	***[TRADE SECRET BEGINS***						
Filed TY204							7
Rebuttal TY2014							8
Jan 2015 Compliance TY 2014							
Apr/May 2015 Prelim Compl TY14							
Apr/May 2015 Prelim Compl TY15							9
June 8, 2015 Reply TY 2014							10
June 8, 2015 Reply TY 2015							11
			TRADE SECRET ENDS]				

1 - Revenue Model, tab Rev, Lines 574-578

2 - Huso Direct, Sch 4, Pg 1

3 - Huso Rebuttal, Sch 7 Pg 1

4 - Jan 16, 2015 Compliance Filing - Sales Actual Data and Related Revenue Calcuations, Att E1, Pg 1

5 - Apr 24, 2015 Compliance Filing - Preliminary Schedules, Sch A10, Pg 5

6 - Apr 24, 2015 Compliance Filing - Preliminary Schedules, Sch A10, Pg 6

7 - Peppin Direct, Sch 4, Pg 2, Line 5

8 - Peppin Rebuttal, Sch 2, Pg 2, Line 5

9 - May 1, 2015 Compliance Filing - CCOSS, Sch A3, Pg 2, Line 5

10 - June 8, 2015 Reply - Att A, Pg 3, Line 5

11 - June 8, 2015 Reply - Att B, Pg 3, Line 5

PUBLIC DOCUMENT
TRADE SECRET INFORMATION AND NON-PUBLIC DATA EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
TY2015 Reconciliation of Total Rate Discounts
($s)

Docket No. E002/GR-13-868
Reply Comments - CCOSS and Revenue Apportionment Schedules
Attachment F - Page 1 of 1

Rebuttal	Res	Sm Non-D	Secondary	Primary	XMSN Transformed	Transmission	Street Lighting	Total
	[TRADE SECRET BEGINS							
Interruptible Discounts								
Economic Discounts								
							TRADE SECRET ENDS]	
Total Discounts	24,542,823	816,851	23,399,999	9,061,779	10,333,023	359,498	0	68,513,975

Compliance	Res	Sm Non-D	Secondary	Primary	XMSN Transformed	Transmission	Street Lighting	Total
	[TRADE SECRET BEGINS							
Interruptible Discounts								
Economic Discounts								
Total Discounts								
							TRADE SECRET ENDS]	

Northern States Power Company **Docket No. E002/GR-13-868**
Electric Utility - State of Minnesota **Reply Comments - CCOSS and Revenue Apportionment Schedules**
2014 Compliance Classification of Other Production O&M Costs **Attachment G - Page 1 of 1**
($ in Thousands)

Expense Category	2014 Compliance Other Production O&M	Percent Energy	Percent Capacity	Energy-Related Portion	Capacity-Related Portion
Variable (Chemicals & Water Use)	$13,005.2	100.0%	0.0%	$13,005.2	$0.0
Fossil	$77,396.9	60.8%	39.2%	$47,057.3	$30,339.6
Combustion Turbine	$43,548.5	0.0%	100.0%	$0.0	$43,548.5
Nuclear	$309,783.4	80.9%	19.1%	$250,614.7	$59,168.6
Combined Cycle	$30,601.8	23.7%	76.3%	$7,252.6	$23,349.2
Hydro	$472.9	85.9%	14.1%	$406.2	$66.7
Wind	$6,823.3	95.6%	4.4%	$6,523.1	$300.2
Total Generation-Related Other Production O&M	**$481,631.9**	**67.45%**	**32.55%**	**$324,859.1**	**$156,772.8**
Corporate Other Production O&M not Assigned to Generation Type	$10,696.3	67.45%	32.55%	$7,214.6	$3,481.7
Regional Market Expense (FERC Codes 575.1 – 575.8)	$7,983.5	67.45%	32.55%	$5,384.9	$2,598.7
Total Other Production O&M	**$500,311.8**	**67.45%**	**32.55%**	**$337,458.6** [1]	**$162,853.1** [2]

[1] See Attachment A, Page 8, Column 1, Line 40

[2] See Attachment A, Page 8, Column 1, Line 39

($ in Thousands)

Expense Category	2014 Compliance Other Production O&M	Percent Energy	Percent Capacity	Energy-Related Portion	Capacity-Related Portion
Variable (Chemicals & Water Use)	$13,005.2	100.0%	0.0%	$13,005.2	$0.0
Fossil	$77,396.9	60.8%	39.2%	$47,057.3	$30,339.6
Combustion Turbine	$43,548.5	0.0%	100.0%	$0.0	$43,548.5
Nuclear	$309,783.4	80.9%	19.1%	$250,614.7	$59,168.6
Combined Cycle	$30,601.8	23.7%	76.3%	$7,252.6	$23,349.2
Hydro	$472.9	85.9%	14.1%	$406.2	$66.7
Wind [1]	$6,823.3	95.6%	4.4%	$6,523.1	$300.2
Total Generation-Related Other Production O&M	**$481,631.9**	**67.45%**	**32.55%**	**$324,859.1**	**$156,772.8**
Corporate Other Production O&M not Assigned to Generation Type	$15,075.4	67.45%	32.55%	$10,168.3	$4,907.1
Regional Market Expense (FERC Codes 575.1 – 575.8)	$7,983.5	67.45%	32.55%	$5,384.9	$2,598.7
Total Other Production O&M	**$504,690.8**	**67.45%**	**32.55%**	**$340,412.3** [2]	**$164,278.5** [3]

[1] Pleasant Valley and Border Winds not scheduled to go on-line until late 2015.
As such there were no O&M costs identified for these plants.

[2] See Attachment B, Page 8, Column 1, Line 40

[3] See Attachment B, Page 8, Column 1, Line 39

The Company's CCOSS includes several customer-based allocators. The customers included in each allocator differ due to the nature of the revenues and costs being allocated and are adjusted to most accurately reflect what caused each cost to occur. Further, interdepartmental customers are not included in customer-based allocators because interdepartmental sales are non-retail. Each CCOSS customer-based allocator is described below.

- C10: The C10 allocator represents the Company's non-duplicative retail customer count. It is equal to the total number of retail customers[1] less Load Management and Protective Lighting customer counts, as these accounts are already counted in another service for the Company. C10 is not used to allocate revenues or costs directly, but is used as the basis for the allocators described below.

- C11: The C11 allocator represents the number of customer connection services on the Company's system and is used to allocate customer connection charge revenues. Load Management and Protective Lighting customers impact customer connection revenues and are therefore added to the C10 allocator counts to form the C11 allocator. C11 is also used in the formation of the customer accounting/billing cost allocator C11WA. Load Management and Protective Lighting customers have an impact on these costs, but their respective customer counts are factored down by factors of 0.5 and 0.1 to reflect the duplicative nature of these services.

- C12: The C12 allocator is the basis used to allocate meter costs. It includes customer counts for Load Management and the Street Lighting count is adjusted to reflect the actual number of Street Lighting meters. The C12 allocator is weighted by each customer class's average meter cost to create the meter cost allocator C12WM.

- C61PS: The C61PS allocator is used to allocate the minimum system/customer-related portion of multi-phase primary distribution line costs. It is equal to the C10 customer counts less transmission transformed and transmission voltage customers, since they do not use the distribution system.

[1] Total number of customers as reported in the Company's January 16, 2015 Compliance Filing.

- C61PS1Ph: The C61PS1Ph allocator is used to allocate the minimum system/customer-related portion of single phase primary distribution line costs. The C61PS allocator described above is adjusted to reflect the percent of customers that receive service off the single phase primary distribution system. This analysis was described on pages 25 and 26 of Company witness Mr. Michael Peppin's Direct Testimony.

- C62Sec: The C62Sec allocator is used to allocate the minimum system/customer-related portion of secondary voltage distribution line and transformer costs. It is equal to the C61PS allocator less primary voltage customers, since they do not use the secondary voltage distribution system.

- C62NL: The C62NL allocator is used to allocate the minimum system/customer-related portion of service line costs. It is equal to the C62Sec allocator, less the number of commercial and industrial customers that are served with an underground service. C&I underground service customers are excluded since these customers install and own their service line.

Northern States Power Company
Electric Utility - State of Minnesota
Sales Reconciliation
(MWh)

Docket No. E002/GR-13-868
Reply Comments
CCOSS and Revenue Apportionment Schedules
Attachment I - Page 3 of 4

		A Final Sales Compliance Filing	B CCOSS E99 Allocator
1	Res	8,359,801	8,359,801
2	Res APL	6,345	
3	Subtotal Res	8,366,146	8,359,801
4	RSH	396,824	396,824
5	Subtotal RSH	396,824	396,824
6	Subtotal Res + RSH	8,762,971	
7	Subtotal Res + RSH w/o APL	8,756,626	8,756,626
8	SCI Non-Demand	961,678	961,678
9	SCI Muni Pumping - Non-Demand		6,343
10	SCI APL	24,171	
11	Subtotal SCI Non-Demand		968,021
12	SCI Demand	12,619,665	12,619,665
13	Subtotal SCI w/o Municipal Pumping	13,605,514	
14	LCI	8,195,137	8,195,137
15	OPA	60,480	60,480
16	SCI Muni Pumping - Non-Demand	6,343	
17	Subtotal OPA w/ Municipal Pumping	66,823	
18	Subtotal SCI Demand, LCI, OPA		20,875,282
19	PSHL	143,362	143,362
20	APL		30,516
21	Subtotal Street Lighting		173,879
22	Total Sales - Retail	30,773,808	30,773,808
23	Interdept	11,228	
24	Total Sales	30,785,036	30,773,808

Shaded values are reported in the 1/16/15 (column A) or 5/1/15 (column B) Compliance Filings

		A Final Sales Compliance Filing	B CCOSS C10 Allocator	C CCOSS C11 Allocator	D CCOSS C12 Allocator	E CCOSS C61PS Allocator
1	Res w/o LM	1,080,232	1,080,232	1,080,232	1,080,232	1,080,232
2	Res LM	998		998	998	
3	Res Subtotal	1,081,230				
4	RSH w/o LM	30,136	30,136	30,136	30,136	30,136
5	RSH LM	2,221		2,221	2,221	
6	Subtotal RSH	32,357				
7	Subtotal Res + RSH	1,113,587		1,113,587	1,113,587	
8	Subtotal Res + RSH w/o LM	1,110,368	1,110,368			1,110,368
9	SCI Non-Demand	85,623	85,623	85,623	85,623	85,623
10	SCI LM	188		188	188	
11	SCI Muni Pumping - Non-Demand		1,013	1,013	1,013	1,013
12	Subtotal SCI Non-Demand		86,636	86,824	86,824	86,636
13	SCI Dmd - Primary/Secondary	44,121	44,121	44,121	44,121	44,121
14	SCI Dmd - Xmsn/Xmsn Transformed	6	6	6	6	
15	Subtotal SCI w/o Municipal Pumping	129,939				
16	LCI Dmd - Primary/Secondary	418	418	418	418	418
17	LCI Dmd - Xmsn/Xmsn Transformed	21	21	21	21	
18	LCI	439				
19	OPA	1,077	1,077	1,077	1,077	1,077
20	SCI Muni Pumping - Non-Demand	1,013				
21	Subtotal OPA w/ Municipal Pumping	2,090				
22	Subtotal SCI Demand, LCI, OPA		45,642	45,642	45,642	45,615
23	Total Cust w/o Str Ltg & Interdept	1,246,054	1,242,647	1,246,054		
24	PSHL	4,081	4,082	4,082	1,698	4,082
25	APL			22,779		
26	Subtotal Street Lighting		4,082	26,861	1,698	4,082
27	Total Customer Count - Retail	1,250,136	1,246,729	1,272,915	1,247,752	1,246,702
28	Interdept	11				
29	Total Customer Count	1,250,147	1,246,729	1,272,915	1,247,752	1,246,702

Shaded values are reported in the 1/16/15 (column A) or 5/1/15 (columns B, C, D, E) Compliance Filings

Northern States Power Company
Electric Utility - State of Minnesota
Ordered Class Revenue Apportionment
($ Thousands)

	A	B	C	D	E	F	G	H	I	J	K	L	M
			B - A	C / A				B - E		H x I		F + J	L / A
	Present	Ordered Revenue at Cost			Revenue at Equal Increase			Cost	Cost Movement		Final Ordered Revenue		
	Revenue[1]	Total	Amt Incr	Pct Incr	Total	Amt Incr	Pct Incr	Difference	Percent	Amount	Total	Amt Incr	Pct Incr
Res	$1,023,121	$1,087,141	$64,019	6.26%	$1,083,849	$60,728	5.94%	$3,291	75%	$2,468	$1,086,318	$63,197	6.18%
Com	$108,086	$113,603	$5,516	5.10%	$114,502	$6,416	5.94%	-$899	100%	-$899	$113,603	$5,516	5.10%
All Dmd	$1,669,134	$1,767,855	$98,721	5.91%	$1,768,207	$99,073	5.94%	-$352	*Remainder Incr.*		$1,768,200	$99,066	5.94%
Ltg	$26,319	$25,841	-$478	-1.81%	$27,881	$1,562	5.94%	-$2,040	*Zero Incr.*		$26,319	$0	0.00%
Retail	$2,826,661	$2,994,440	$167,779	5.94%	$2,994,440	$167,779	5.94%	$0			$2,994,440	$167,779	5.94%
Other Incr		$306	$306								$306	$306	
Total	$2,826,661	$2,994,746	$168,085	5.95%							$2,994,746	$168,085	5.95%
InterDept	$962	$962									$962		
Total+ID	$2,827,623	$2,995,708	$168,085	5.94%							$2,995,708	$168,085	5.94%

Percent of Retail	A	B	E	H	K	L	L / H
Res	36.20%	36.31%	36.20%	0.11%	36.28%	0.08%	75%
Com	3.82%	3.79%	3.82%	-0.03%	3.79%	-0.03%	
All Dmd	59.05%	59.04%	59.05%	-0.01%	59.05%	0.00%	
Ltg	0.93%	0.86%	0.93%	-0.07%	0.88%	-0.05%	
Retail	100.00%	100.00%	100.00%	0.00%	100.00%	0.00%	

(1) Based on Jan-Dec 2014 Actuals (Weather-Normalized) with Year 2015 LCI Adjustment

CERTIFICATE OF SERVICE

I, Lynnette Sweet, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States Mail at Minneapolis, Minnesota

xx electronic filing

Docket No. E002/GR-13-868

Dated this 8th day of June 2015

/s/

____

Lynnette Sweet

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_13-868_Official
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_13-868_Official
Alison C	Archer	alison.c.archer@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 5 Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_13-868_Official
Ryan	Barlow	Ryan.Barlow@ag.state.mn.us	Office of the Attorney General-RUD	445 Minnesota Street Bremer Tower, Suite 1400 St. Paul, Minnesota 55101	Electronic Service	Yes	OFF_SL_13-868_Official
James J.	Bertrand	james.bertrand@leonard.com	Leonard Street & Deinard	150 South Fifth Street, Suite 2300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_13-868_Official
William A.	Blazar	bblazar@mnchamber.com	Minnesota Chamber Of Commerce	Suite 1500 400 Robert Street North St. Paul, MN 55101	Electronic Service	No	OFF_SL_13-868_Official
Michael	Bradley	mike.bradley@lawmoss.com	Moss & Barnett	150 S. 5th Street, #1200 Minneapolis, MN 55402	Electronic Service	Yes	OFF_SL_13-868_Official
James	Canaday	james.canaday@ag.state.mn.us	Office of the Attorney General-RUD	Suite 1400 445 Minnesota St. St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_13-868_Official
Aakash	Chandarana	Aakash.Chandara@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 5 Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_13-868_Official
Jeanne	Cochran	Jeanne.Cochran@state.mn.us	Office of Administrative Hearings	P.O. Box 64620 St. Paul, MN 55164-0620	Electronic Service	Yes	OFF_SL_13-868_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_13-868_Official
Jeffrey A.	Daugherty	jeffrey.daugherty@centerpointenergy.com	CenterPoint Energy	800 LaSalle Ave Minneapolis, MN 55402	Electronic Service	No	OFF_SL_13-868_Official
James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.	414 Nicollet Mall, Fifth Floor Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_13-868_Official
Ian	Dobson	ian.dobson@ag.state.mn.us	Office of the Attorney General-RUD	Antitrust and Utilities Division 445 Minnesota Street, 1400 BRM Tower St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_13-868_Official
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	Yes	OFF_SL_13-868_Official
Stephen	Fogel	Stephen.E.Fogel@XcelEnergy.com	Xcel Energy Services, Inc.	816 Congress Ave, Suite 1650 Austin, TX 78701	Electronic Service	No	OFF_SL_13-868_Official
Benjamin	Gerber	bgerber@mnchamber.com	Minnesota Chamber of Commerce	400 Robert Street North Suite 1500 St. Paul, Minnesota 55101	Electronic Service	Yes	OFF_SL_13-868_Official
Michael	Hoppe	il23@mtn.org	Local Union 23, I.B.E.W.	932 Payne Avenue St. Paul, MN 55130	Electronic Service	No	OFF_SL_13-868_Official
Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law	2265 Roswell Road Suite 100 Marietta, GA 30062	Electronic Service	No	OFF_SL_13-868_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Linda	Jensen	linda.s.jensen@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota Street St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_13-868_Official
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	Yes	OFF_SL_13-868_Official
Sarah	Johnson Phillips	sjphillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_13-868_Official
Mark J.	Kaufman	mkaufman@ibewlocal949.org	IBEW Local Union 949	12908 Nicollet Avenue South Burnsville, MN 55337	Electronic Service	No	OFF_SL_13-868_Official
Thomas G.	Koehler	TGK@IBEW160.org	Local Union #160, IBEW	2909 Anthony Ln St Anthony Village, MN 55418-3238	Electronic Service	No	OFF_SL_13-868_Official
Mara	Koeller	mara.n.koeller@xcelenergy.com	Xcel Energy	414 Nicollet Mall 5th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_13-868_Official
Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_13-868_Official
Ganesh	Krishnan	ganesh.krishnan@state.mn.us	Public Utilities Commission	Suite 350121 7th Place East St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_13-868_Official
Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	OFF_SL_13-868_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_13-868_Official
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_13-868_Official
Paula	Maccabee	Pmaccabee@justchangelaw.com	Just Change Law Offices	1961 Selby Ave Saint Paul, MN 55104	Electronic Service	No	OFF_SL_13-868_Official
Peter	Madsen	peter.madsen@ag.state.mn.us	Office of the Attorney General-DOC	Bremer Tower, Suite 1800 445 Minnesota Street St. Paul, Minnesota 55101	Electronic Service	Yes	OFF_SL_13-868_Official
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_13-868_Official
Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	414 Nicollet Mall 7th Floor Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_13-868_Official
Connor	McNellis	cmcnellis@larkinhoffman.com	Larkin Hoffman Daly & Lindgren Ltd.	8300 Norman Center Drive Suite 1000 Minneapolis, MN 55437	Electronic Service	No	OFF_SL_13-868_Official
Brian	Meloy	brian.meloy@stinsonleonard.com	Stinson,Leonard, Street LLP	150 S 5th St Ste 2300 Minneapolis, MN 55402	Electronic Service	Yes	OFF_SL_13-868_Official
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_13-868_Official
Andrew	Moratzka	apmoratzka@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	Yes	OFF_SL_13-868_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
David W.	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	Suite 300 200 South Sixth Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_13-868_Official
Regulatory	Records	Regulatory.Records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	Yes	OFF_SL_13-868_Official
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	Yes	OFF_SL_13-868_Official
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_13-868_Official
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	Ste 122 9100 W Bloomington Frwy Bloomington, MN 55431	Electronic Service	Yes	OFF_SL_13-868_Official
Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.	76 W Kellogg Blvd St. Paul, MN 55102	Electronic Service	No	OFF_SL_13-868_Official
Ron	Spangler, Jr.	rlspangler@otpco.com	Otter Tail Power Company	215 So. Cascade St. PO Box 496 Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_13-868_Official
Byron E.	Starns	byron.starns@leonard.com	Leonard Street and Deinard	150 South 5th Street Suite 2300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_13-868_Official
James M.	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	470 U.S. Bank Plaza 200 South Sixth Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_13-868_Official
Eric	Swanson	eswanson@winthrop.com	Winthrop Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_13-868_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Lisa	Veith	lisa.veith@ci.stpaul.mn.us	City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Electronic Service	No	OFF_SL_13-868_Official
Samantha	Williams	swilliams@nrdc.org	Natural Resources Defense Council	20 N. Wacker Drive Ste 1600 Chicago, IL 60606	Electronic Service	No	OFF_SL_13-868_Official
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_13-868_Official
Patrick	Zomer	Patrick.Zomer@lawmoss.com	Moss & Barnett a Professional Association	150 S. 5th Street, #1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_13-868_Official