BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, Minnesota 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-23147

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY, D/B/A XCEL ENERGY, FOR AUTHORITY TO INCREASE RATES FOR ELECTRIC SERVICE IN MINNESOTA	MPUC Docket No. E002/GR-15-826 OAH Docket No. 19-2500-33074

DIRECT ATTACHMENTS OF NANCY A. CAMPBELL (PART I – NAC-1 TO NAC-20)

ON BEHALF OF

THE DIVISION OF ENERGY RESOURCES OF
THE MINNESOTA DEPARTMENT OF COMMERCE

JUNE 14, 2016

PUBLIC DOCUMENT

SUMMARY OF ATTACHMENTS TO THE DIRECT
TESTIMONY OF NANCY A. CAMPBELL

MPUC Docket No. E002/GR-15-826
OAH Docket No. 19-2500-33074

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

Xcel Energy			
Docket No.:	E002/GR-15-826		
Response To:	Department of Commerce	Information Request No.	132
Requestor:	Nancy Campbell, Angela Byrne, Dale Lusti		
Date Received:	March 14, 2016		

Question:

Reference: Commission's Order dated November 13, 2015 in Docket No. E,G002/D-15-46
Subject: RL Depreciation Adjustment

Please provide all adjustments and calculations for all test years (both 3 and 5 year rate plans) to reflect the Commission's decision in the referenced docket. Please include narrative to show adjustment is consistent with the Commission's Order.

Response:

Please see Attachment A for a calculation of the five-year impact of the Commission's decision.

Please see the Company's answer to DOC Information Request No. 133 in this docket for a discussion of the five-year settlement offer. In particular, please note that the five-year settlement offer is informed by cost forecasts over the plan term but is not the result of a Cost of Service study in each year.

The remaining life for Angus Anson Units 2 & 3 was changed from 3.8 years to 10 years. The remaining life for Granite City was changed from 3.4 years to 8 years. The remaining life for Sherco Unit 1 was changed from 7 years to 10 years. Approval for these lives is consistent with the Commission's November 13, 2015 Order in Docket No. E,G002/D-15-46, order points 2 and 4. These adjustments were included in interim rates and we plan on including the adjustments in the test year cost of service in rebuttal testimony.

For narrative discussing these adjustments, please see the Direct Testimony for Company witness Ms. Lisa H. Perkett, on pages 36 and 37. Additionally, schedule support for the years 2016, 2017, and 2018 are provided in Exhibit___(AEH-1), Schedule 26 of Company witness Ms. Anne E. Heuer's Direct Testimony found on page 230 of the public filing.

Witness:	Lisa H. Perkett/ Anne E. Heuer
Preparer:	Michael Bliss/Nicholas Hanson
Title:	Senior Rate Analyst/Senior Accounting Analyst
Department:	Revenue Requirements North/Capital Asset Accounting
Telephone:	612-330-6216/612-330-7850
Date:	March 24, 2016

Annual Revenue Requirement
Capital Adjustment - MN Remaining Life
2016-2018 MYRP plus 2019-2020 Fcst
(000's)

		Total Company					MN Jurisdiction				
	Rate Analysis	2016	2017	2018	2019	2020	2016	2017	2018	2019	2020
1	Average Balances:										
2	Plant Investment	-	-	-	-	-	-	-	-	-	-
3	Depreciation Reserve	(5,602)	(16,881)	(30,114)	(48,478)	(71,497)	(4,893)	(14,745)	(26,303)	(42,344)	(62,450)
4	CWIP	-	-	-	-	-	-	-	-	-	-
5	Accumulated Deferred Taxes	2,286	6,889	12,289	19,784	29,178	1,997	6,017	10,734	17,280	25,486
6	Average Rate Base = line 1 - line 3 + line 4 - line 5	3,316	9,992	17,824	28,694	42,319	2,896	8,727	15,569	25,064	36,964
7											
8	Revenues:										
9	Interchange Agreement offset = -line 37 x line 45 x line 46						1,517	1,437	1,844	2,589	2,775
10											
11	Expenses:										
12	Book Depreciation	(11,205)	(11,352)	(15,114)	(21,615)	(24,423)	(9,787)	(9,916)	(13,201)	(18,880)	(21,332)
13	Annual Deferred Tax	4,573	4,633	6,168	8,821	9,967	3,994	4,047	5,387	7,705	8,706
14	ITC Flow Thru	-	-	-	-	-	-	-	-	-	-
15	Property Taxes	-	-	-	-	-	-	-	-	-	-
16	subtotal expense = lines 12 thru 15	(6,632)	(6,720)	(8,946)	(12,794)	(14,456)	(5,793)	(5,869)	(7,814)	(11,175)	(12,627)
17											
18	Tax Preference Items:										
19	Tax Depreciation & Removal Expense	-	-	-	-	-	-	-	-	-	-
20	Avoided Tax Interest	-	-	-	-	-	-	-	-	-	-
21											
22	AFUDC	-	-	-	-	-	-	-	-	-	-
23											
24	Returns:										
25	Debt Return = line 6 x (line 38 + line 39)	74	224	399	643	948	65	197	352	564	843
26	Equity Return = line 6 x (line 40 + line 41)	169	510	909	1,463	2,158	148	445	794	1,278	1,885
27											
28	Tax Calculations:										
29	Equity Return = line 26	169	510	909	1,463	2,158	148	445	794	1,278	1,885
30	Taxable Expenses = lines 12 thru 14	(6,632)	(6,720)	(8,946)	(12,794)	(14,456)	(5,793)	(5,869)	(7,814)	(11,175)	(12,627)
31	plus Tax Additions = line 20	-	-	-	-	-	-	-	-	-	-
32	less Tax Deductions = (line 19 + line 22)	-	-	-	-	-	-	-	-	-	-
33	subtotal	(6,463)	(6,210)	(8,037)	(11,331)	(12,298)	(5,645)	(5,424)	(7,020)	(9,897)	(10,741)
34	Tax gross-up factor = t / (1-t) from line 44	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611
35	Current Income Tax Requirement = line 33 x line 34	(4,560)	(4,382)	(5,671)	(7,995)	(8,677)	(3,983)	(3,827)	(4,953)	(6,983)	(7,579)
36											
37	Total Revenue Requirements = line 16 + line 25 + line 26 + line 35 - line 22	(10,949)	(10,368)	(13,308)	(18,683)	(20,027)	(8,046)	(7,618)	(9,777)	(13,727)	(14,703)

	Capital Structure	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**
38	**Long Term Debt**	**2.2200%**	**2.2100%**	**2.2100%**	**2.1800%**	**2.2000%**
39	**Short Term Debt**	**0.0200%**	**0.0500%**	**0.0500%**	**0.0700%**	**0.0800%**
40	**Preferred Stock**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
41	**Common Equity**	**5.1000%**	**5.1000%**	**5.1000%**	**5.1000%**	**5.1000%**
42	**Required Rate of Return**	**7.3400%**	**7.3600%**	**7.3600%**	**7.3500%**	**7.3800%**
43	**PT Rate**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
44	**Tax Rate (MN)**	**41.3700%**	**41.3700%**	**41.3700%**	**41.3700%**	**41.3700%**
45	**MN JUR Demand**	**87.3461%**	**87.3461%**	**87.3461%**	**87.3461%**	**87.3461%**
46	**IA Demand**	**84.1349%**	**84.1349%**	**84.1349%**	**84.1349%**	**84.1349%**

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

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

Xcel Energy			
Docket No.:	E002/GR-15-826		
Response To:	Department of Commerce	Information Request No.	130
Requestor:	Nancy Campbell, Angela Byrne, Dale Lusti		
Date Received:	March 14, 2016		

Question:

Reference: Direct Testimony of Aakash Chandarana p 53-54 and Docket No. E002/CN-12-1240 and E002/M-14-789 Xcel comments dated August 27, 2015
Subject: Mankato Energy Center II In-Service Date

In the referenced docket Xcel indicated on page 6 of its comments that the expected in-service or commercial operation date for Mankato Energy Center II is expected to be June 1, 2019. Please provide any information the Company has that would support a different in-service or commercial operation date.

Response:

The commercial operation date as stated in the First Amendment to the PPA filed with the Commission August 27, 2015 in Docket Nos. E002/CN-12-1240 and E002/M-14-789 can be no later than June 1, 2019. Please see Trade Secret Attachment A to this response for a copy of the First Amendment to the PPA.

Please note Attachment A to this response is marked "Non-Public," as it contains information we consider to be trade secret data as defined by Minn. Stat. §13.37(1)(b). The information derives an independent economic value from not being generally known or readily ascertainable by others who could obtain a financial advantage from its use. Based on its economic value, the Company maintains this information as trade secret.

Witness:	Aakash Chandarana
Preparer:	Jeff Klein
Title:	Manager, Structured Purchases
Department:	Purchased Power
Telephone:	303.571.2732
Date:	March 25, 2016

414 Nicollet Mall
Minneapolis, MN 55401

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

August 27, 2015

—Via Electronic Filing—

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

RE: FIRST AMENDMENT TO A POWER PURCHASE AGREEMENT WITH MANKATO ENERGY CENTER II, LLC
COMPETITIVE RESOURCE ACQUISITION - THERMAL
DOCKET NO. E002/CN-12-1240 AND E002/M-14-789

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, and Mankato Energy Center II, LLC have executed the First Amendment to their Power Purchase Agreement (PPA).

The one significant modification is the extension of the condition precedent date to April 1, 2016 which allows the Company to terminate the PPA pending all necessary regulatory approval. This extension is intended to accommodate the length of the North Dakota Advance Determination of Prudence (ADP) process which we expect to conclude prior to the condition precedent date in the amended contract. The Amendment is enclosed as Attachment A for reference.

Please note portions of the Amendment to the PPA are marked as "Non-Public," as it contains information we consider to be trade secret data as defined by Minn. Stat. §13.37(1)(b). The information derives an independent economic value from not being generally known or readily ascertainable by others who could obtain a financial advantage from its use. Based on its economic value, the Company maintains this information as trade secret.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service

PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED

list. Please contact me at aakash.chandarana@xcelenergy.com or (612) 215-4663 if you have any questions regarding this filing.

Sincerely,

/s/

AAKASH CHANDARANA
REGIONAL VICE PRESIDENT
RATES AND REGULATORY AFFAIRS

Enclosure
c: Service List

Amendment No. 1

To

Power Purchase Agreement

Between

Northern States Power Company And Mankato Energy Center II, LLC

This Amendment No. 1 ("Amendment No. 1") to Power Purchase Agreement Between Northern States Power Company and Mankato Energy Center II, LLC dated April 28, 2015 ("Power Purchase Agreement" or "PPA") is made this day, August 13 , 2015, by and between Northern States Power Company ("Company") and Mankato Energy Center II, LLC ("Seller"). Seller and Company are hereinafter referred to individually as a "Party" and collectively as the "Parties." Capitalized terms used herein but not defined shall have the meanings set forth in the PPA.

WHEREAS, the Parties have entered into the Power Purchase Agreement for the sale and purchase of capacity and associated energy from Seller's Mankato II electric generating plant; and

WHEREAS, the Parties desire to modify certain provisions of the PPA as a result of the delayed receipt of State Regulatory Approval from the State Regulatory Agency, as such terms are defined in the PPA, which provisions are specifically Section 2.4- Early Termination, Section 6.1- Company CPs, Section 6.2 – Seller CPs, and Exhibit B- Construction Milestones.

NOW THEREFORE, in consideration of the foregoing and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, and intending to be legally bound thereby, the Parties hereby agree as follows:

1. The first sentence of Article 2.4 of the Power Purchase Agreement is hereby deleted in its entirety and replaced by the following:

   "2.4 Early Termination. Company has an option to terminate this PPA for its convenience ("Early Termination") by providing Notice to Seller on or before April 1, 2016; *provided, however, that* if on or before such date Company has pursuant to Section 6.1(B) filed a Minnesota Cost Recovery Request as that term is defined in Section 6.1(B) with the Minnesota Public Utilities Commission ("MPUC") and provided Notice thereof to Seller, the deadline for Company to exercise the Early Termination right in this Section 2.4 shall be extended to the earlier of (i) 30 Days following the date on which the MPUC issues a written order approving the Minnesota Cost Recovery Request or (ii) **[Trade Secret Data Begins… …Trade Data Secret Ends]**."

2. Article 6.1 of the Power Purchase Agreement is hereby deleted in its entirety and replaced by the following:

"6.1 Company CPs.

(A) No later than 15 Business Days after execution of this PPA, Company may make written request for State Regulatory Approval. Seller acknowledges and agrees that the Company filed for State Regulatory Approval of this PPA on February 13, 2015.

(B) Company shall have the right to terminate this PPA pursuant to this Section 6.1, without any further financial or other obligation to Seller as a result of such termination, by Notice to Seller not more than 10 Business Days after the earlier of: (i) receipt of any written order from a State Regulatory Agency rejecting State Regulatory Approval or granting such approval with conditions reasonably and materially unsatisfactory to Company; or (ii) March 31, 2016, in the event Company has not received State Regulatory Approval as of such date.

Notwithstanding the foregoing, in the event Company has not received State Regulatory Approval as of March 31, 2016, or by such date the State Regulatory Agency has rejected this PPA or has limited or prohibited Company's recovery of its costs and payments under this PPA, Company shall within 10 Business Days after the earlier of (i) March 31, 2016, in the event Company has not received State Regulatory Approval as of such date, or (ii) the receipt of the State Regulatory Agency's written order rejecting the PPA or limiting/prohibiting cost recovery under the PPA file a request with the MPUC to approve recovery from Minnesota ratepayers of the PPA's costs and payments that have not been approved by the State Regulatory Agency for recovery from North Dakota ratepayers ("Minnesota Cost Recovery Request"), and shall at the time of such filing provide Notice thereof to Seller.

Upon Company making such filing and providing such Notice, Company shall retain the right to terminate this PPA at no cost to Company, notwithstanding anything to the contrary in Section 2.4, until no later than 10 Business Days after the earlier of (i) July 15, 2016, in the event that, as of such date, the MPUC has failed to issue a written order that is a final and unappealable determination of Company's Minnesota Cost Recovery Request on the merits or (ii) receipt of a written order from the MPUC that is final and unappealable (a) rejecting the Company's Minnesota Cost Recovery Request, or (b) granting the Company's Minnesota Cost Request with conditions reasonably and materially unsatisfactory to the Company. For avoidance of doubt, any delay of COD that results from the Company's exercising its rights under this Section 6.1(B) does not constitute a delay of COD pursuant to Section 2.3 and Company shall not be liable to Seller for any Demobilization Costs or Re-mobilization Costs Seller incurs as a result of the delay in COD.

If Company fails to terminate this PPA in the time allowed by this Section, Company shall be deemed to have waived its right to terminate this PPA under this Section and, subject to the other terms and conditions of this PPA, this PPA shall remain in full force and effect thereafter."

3. The Table in Section 6.2 of the Power Purchase Agreement is hereby deleted and replaced in its entirety with the following:

Condition Precedent	Deadline Date
Seller has obtained the Air Permit, which Permit does not contain conditions reasonably and materially unsatisfactory to Seller.	September 1, 2017
Seller has obtained the Site Permit, which Permit does not contain conditions reasonably and materially unsatisfactory to Seller.	June 1, 2017
Transmission Owner, Transmission Authority and Seller have entered into the Interconnection Agreement.	June 1, 2016
Approval of this PPA, in the form submitted by Company to the MPUC for approval, by the board of directors of Calpine Corporation.	April 15, 2015
Approval of this PPA by the board of directors of Calpine Corporation in the event any conditions are added or modifications are made to this PPA after its submittal to the MPUC for approval	Thirty (30) Days after issuance of any order requiring such additional conditions or modifications

4. The following term and meaning corresponding thereto shall be added to Exhibit A, Definitions of the Power Purchase Agreement:

""Minnesota Cost Recovery Request" shall have the meaning set forth in Section 6.1(B)."

5. The Table in Exhibit B, Construction Milestones of the Power Agreement is hereby deleted in its entirety and replaced by the following:

Construction Milestone	Outcome
[Trade Secret Data Begins…	
	Company shall have obtained State Regulatory Approval.
	Seller and all required counterparties have executed major procurement contracts, the Construction Contract (Limited Notice To Proceed Only), any operating agreements, and the Interconnection Agreement needed to commence construction of the Facility.
	Seller shall have achieved closing on financing for the Facility or provided Company with proof of financial capability to construct the

	Facility.
	Seller shall have laid the foundation for generating facilities and step-up transformation facilities.
	The turbine(s)/generator(s)/step-up transformer shall have been delivered to, and set on foundation at, the Site.
	All Network Upgrades associated with obtaining NITS are completed.
	All fuel supply and transportation arrangements have been put in place and fuel interconnection facilities in have been constructed and are operational.
	Seller shall have constructed Seller's Interconnection Facilities and such facilities are capable of being energized
	Commissioning of the Facility commences.
	Seller shall have obtained either (i) unconditional ERIS and unconditional NITS, or (ii) unconditional NRIS.
	Seller shall have obtained MISO accreditation of the Facility as a Capacity Resource
	Commercial Operation Milestone
…Trade Secret Data Ends]	
June 1, 2019	Commercial Operation Date

5. The terms and provisions contained in this Amendment No. 1 to the PPA constitute the entire agreement between Company and Seller with respect to the amendment of the PPA and shall supersede all previous communications, representations, or agreements, either verbal or written, between Company and Seller regarding amendment of the PPA. This Amendment No. 1 may be amended, changed, modified, or altered in accordance with the terms of the PPA, *provided, however, that* any such amendment, change, modification, or alteration shall be in writing and executed by both Parties.

6. This Amendment No. 1 is binding upon and shall inure to the benefit of the Parties hereto and their respective successors, legal representatives, and assigns.

7. Except as specifically provided in this Amendment No. 1, no other amendments, revisions or changes are or have been made to the PPA.

8. Upon the effectiveness of this Amendment No. 1, each reference in this Amendment No. 1 to "this PPA", "the PPA", "thereunder", "hereto", "herein", or words of like import shall mean and be a reference to the PPA, as amended hereby.

9. This Amendment No. 1 may be executed in one or more counterparts, and each executed counterpart shall have the same force and effect as an original instrument.

[remainder of this page intentionally left blank]

IN WITNESS WHEREOF, the Parties have executed this Amendment No. 1 as of the date first set forth above.

Seller:

MANKATO ENERGY CENTER II, LLC

By ______________________

Name Jennings Goodman

Title Vice President

Company

XCEL ENERGY SERVICES INC. AS AGENT FOR

NORTHERN STATES POWER COMPANY, a Minnesota Corporation

By ______________________

Name Tim Kawakami

Title Director, Purchased Power

CERTIFICATE OF SERVICE

I, SaGonna Thompson, 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 Nos. E002/CN-12-1240
E002/M-14-789

Dated this 27th day of August 2015

/s/

____
SaGonna Thompson
Regulatory Administrator

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
David	Aafedt	daafedt@winthrop.com	Winthrop & Weinstine, P.A.	Suite 3500, 225 South Sixth Street Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_12-1240_Official
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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	No	OFF_SL_12-1240_Official
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Christina	Brusven	cbrusven@fredlaw.com	Fredrikson Byron	200 S 6th St Ste 4000 Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_12-1240_Official
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James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.	414 Nicollet Mall, Fifth Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_12-1240_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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	No	OFF_SL_12-1240_Official
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John	Flumerfelt	jflumerfelt@calpine.com	CalpineCorporation	500 Delaware Ave. Wilmington, DE 19801	Electronic Service	No	OFF_SL_12-1240_Official
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Todd J.	Guerrero	todd.guerrero@kutakrock.com	Kutak Rock LLP	Suite 1750 220 South Sixth Street Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_12-1240_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Michael	Hoppe	il23@mtn.org	Local Union 23, I.B.E.W.	932 Payne Avenue St. Paul, MN 55130	Electronic Service	No	OFF_SL_12-1240_Official
Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law	2265 Roswell Road Suite 100 Marietta, GA 30062	Electronic Service	No	OFF_SL_12-1240_Official
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_12-1240_Official
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_12-1240_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_12-1240_Official
Karen	Kromar	karen.kromar@state.mn.us	MN Pollution Control Agency	520 Lafayette Rd Saint Paul, MN 55155	Electronic Service	No	OFF_SL_12-1240_Official
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_12-1240_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	No	OFF_SL_12-1240_Official
Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Electronic Service	No	OFF_SL_12-1240_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	No	OFF_SL_12-1240_Official
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_12-1240_Official
Thomas	Melone	Thomas.Melone@AllcoUS.com	Minnesota Go Solar LLC	222 South 9th Street Suite 1600 Minneapolis, Minnesota 55120	Electronic Service	No	OFF_SL_12-1240_Official
Brian	Meloy	brian.meloy@stinsonleonard.com	Stinson,Leonard, Street LLP	150 S 5th St Ste 2300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_12-1240_Official
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Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	Ste 122 9100 W Bloomington Frwy Bloomington, MN 55431	Electronic Service	No	OFF_SL_12-1240_Official
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Xcel Energy
Docket No.: E002/GR-15-826
Response To: Department of Commerce   Information Request No. 131
Requestor: Nancy Campbell, Angela Byrne, Dale Lusti
Date Received: March 14, 2016

Question:

Reference: Direct Testimony of Aakash Chandarana p 53-54 and Docket No. E002/CN-12-1240 and E002/M-14-789 Xcel comments dated August 27, 2015
Subject: Mankato Energy Center II In-Service Date)

Please provide all adjustments and calculations for all test years (both 3 and 5 year rate plans) to reflect the Mankato Energy Center II in-service date from the January 1, 2018 rate case in-service date to the June 1, 2019 in-service date.

Response:

Please see Attachment A for all of the adjustments and calculations for shifting the Mankato Energy Center II commercial operation date from January 1, 2018 to June 1, 2019.

Please see the Company's answer to DOC Information Request No. 133 in this docket for a discussion of the five-year settlement offer. In particular, please note that the five-year settlement offer is informed by cost forecasts over the plan term but is not the result of a Cost of Service study in each year.

Preparer: Michael Bliss
Title: Senior Rate Analyst
Department: Revenue Requirements North
Telephone: 612-330-6216
Date: March 24, 2016

Line No.	Description	Purchased Demand 2016	2017	2018	2019	2020
	Operating Revenues					
1	Other Operating	0	0	(3,660)	(1,505)	21
2	**Total Operating Revenues**	$0	$0	($3,660)	($1,505)	$21
	Expenses					
	Operating Expenses:					
3	Power Production	$0	$0	($23,071)	($9,483)	$131
4	Total Operating Expenses	$0	$0	($23,071)	($9,483)	$131
	Taxes:					
5	Federal & State Income Tax	0	0	8,030	3,301	(46)
6	Total Taxes	$0	$0	$8,030	$3,301	($46)
7	**Total Expenses**	$0	$0	($15,041)	($6,183)	$86
8	**Total Operating Income**	$0	$0	$11,380	$4,678	($65)
	Calculation of Revenue Requirements					
9	Operating Income	0	0	11,380	4,678	(65)
10	Income Deficiency	0	0	(11,380)	(4,678)	65
11	Revenue Deficiency	**$0**	**$0**	**($19,411)**	**($7,979)**	**$111**
	Calculation of Income Taxes					
12	Operating Revenue	$0	$0	($3,660)	($1,505)	$21
13	- Operating Exp	0	0	(23,071)	(9,483)	131
14	Operating Income before Adjs	$0	$0	$19,411	$7,979	($111)
15	State Taxable Income	$0	$0	$19,411	$7,979	($111)
16	State Income Tax before Credits	$0	$0	$1,902	$782	($11)
17	State Tax Credits	$0	$0	$0	$0	$0
18	Federal Taxable Income	$0	$0	$17,508	$7,197	($100)
19	Fed Income Tax before Credits	$0	$0	$6,128	$2,519	($35)
20	Federal Tax Credits	$0	$0	$0	$0	$0
21	Income Tax	$0	$0	$8,030	$3,301	($46)

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Xcel Energy
Docket No.: E002/GR-15-826
Response To: Department of Commerce Information Request No. 141
Requestor: Nancy Campbell, Angela Byrne, Dale Lusti
Date Received: March 14, 2016 **SUPPLEMENT**

Question:

Reference: Direct Testimony of Charles Burdick p 39
Subject: Bonus Tax Depreciation

Please calculate all tax updates (including but not limited to bonus tax depreciation) due to the December 2015 tax legislation approved and provide the effect on all test years 2016 to 2020. Please include a narrative to explain and support all calculations and the effect on all test years 2016 to 2020.

Response:

Please see the Company's response to XLI Information Request No. 35 in this docket for the impacts for 2016-2018. We will supplement this response with forecast impacts for 2019-2020 when that analysis is complete.

Supplement:

Please see the Company's supplemented response to information request XLI-35 which includes an analysis for 2019-2020.

Witness: Anne Heuer and Charles Burdick
Preparer: Charles Burdick
Title: Manager of Revenue Analysis
Department: Revenue Requirements North
Telephone: 612-330-6646
Date: April 8, 2016 **Supplemented:** May 26, 2016

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Xcel Energy
Docket No.: E002/GR-15-826
Response To: Xcel Large Industrials Information Request No. 35
Requestor: Andrew Moratzka, Sarah Johnson Phillips, Emma J. Fazio
Date Received: March 4, 2016 **SUPPLEMENT**

Question:

On December 18, 2015, the President signed the Protecting Americans from Tax Hikes (PATH) Act of 2015 into law. The PATH Act extended bonus depreciation and made the R&D credits permanent as well as other changes. Please provide all impacts of the PATH Act of 2015 on the revenue requirements presented in this case for the 2016 Test Year and each of the Plan Years submitted in this case. At a minimum, as part of this response, provide revised versions of the Schedules submitted with the Direct Testimonies of Anne E. Heuer and Charles R. Burdick that are impacted by the passage of the PATH Act of 2015 in this case as well as a revised version of Schedule 11 provided with the Direct Testimony of Lisa H. Perkett. Include all workpapers and calculations used in determining the various impacts of the PATH Act of 2015 on the Test Year and Plan Years revenue requirements in this case.

Response:

A brief overview of the tax legislative changes as a result of the Protecting Americans from Tax Hikes (PATH) Act of 2015 which is also known as the Consolidated Appropriations Act of 2016 will be discussed prior to addressing the impact to the revenue requirements in this case.

Legislative Overview:

Consolidated Appropriations Act, 2016 — In December 2015, the Consolidated Appropriations Act, 2016 (Act) was signed into law. The Act provides for the following:

Bonus Depreciation
Immediate expensing, or "bonus depreciation," of 50 percent for property placed in service in 2015, 2016, and 2017; 40 percent for property placed in service in 2018; and 30 percent for property placed in service in 2019. The remaining basis of the property depreciates according to ordinary MACRS depreciation method and life. In addition, long production period property (LPPP) placed in service in 2020 will be eligible for bonus depreciation for costs incurred prior to 2020. The definition of qualifying property did not change.

Wind Production Tax Credits (PTCs)
PTCs at 100 percent of the credit rate for wind energy projects that begin construction by the end of 2016; 80 percent of the credit rate for projects that begin construction in 2017; 60 percent of the credit rate for projects that begin construction in 2018; and 40 percent of the credit rate for projects that begin construction in 2019. The wind energy PTC was not extended for projects that begin construction after 2019. In addition to the requirement to begin construction, taxpayers also have to show continuous construction until the project is completed.

Solar Investment Tax Credits (ITCs)
ITCs at 30 percent for commercial solar projects that begin construction by the end of 2019; 26 percent for projects that begin construction in 2020; 22 percent for projects that begin construction in 2021; and 10 percent for projects thereafter. The ITC was previously based on when the projects were placed in service rather than when they begin construction. The definition of qualifying property did not change.

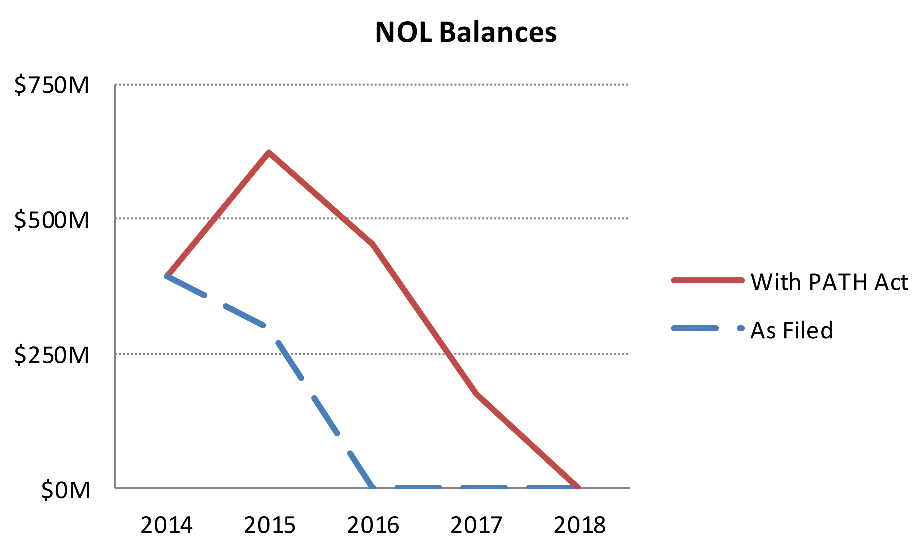
Federal Research & Experimentation (R&E) credit
The Federal R&E credit incentivizes research activities by reducing tax liabilities for companies that spend money on research. The credit is equal to a certain percentage of a business' qualified research expenses in excess of a base amount. The research credit attempts to boost business investment in basic and applied research by reducing the after-tax cost of undertaking qualified research above a base amount, which in theory approximates the amount a company would invest in R&E in the absence of the credit. The Federal R&E credit was permanently extended with no changes to the calculation.

Revenue Requirement Impacts:

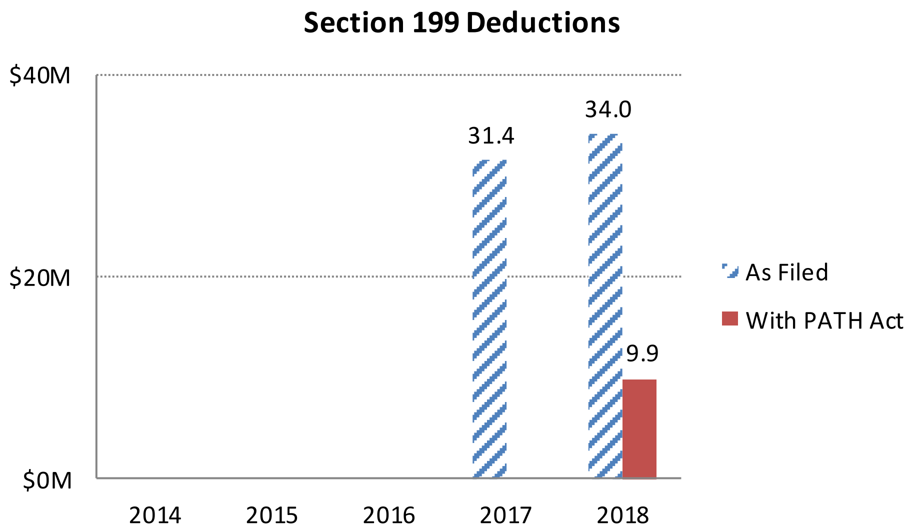
The introduction of the additional tax depreciation pushes out our utilization of both the Net Operating Loss (NOL) balance as well as usage of federal tax credits and reduces the ability of the Company to claim a Federal Section 199 Deduction. The order in which Federal tax benefits are utilized is based on the Internal Revenue Code (IRC) and is also dependent upon the amount of taxable income for the period. Assuming that the amount of taxable income for the period was larger than all of the available tax benefits, the following usage pattern would occur:

1. The Net Operating Loss (NOL) deduction is applied first and the balance must be fully exhausted before the utilization of the other tax benefits may begin.
2. The next tax benefit that may be applied is the Section 199 deduction which may only apply to the initial year it is generated as this tax benefit is prohibited from being deferred to a future period.
3. Once those deductions are fully consumed, the Company is allowed to use tax credits that have been deferred such as the Production Tax Credit or the Federal R&E credit.

Previously, the Company had forecasted the full consumption of the NOL balance in the 2016 test year. As a result, the Company was able to generate a Federal 199 Tax Deduction in 2017 and 2018 which provided tax benefits that reduced the revenue requirements during those years. The Federal 199 deduction is generated only after the utilization of the entire NOL balance and is a unique deduction in that it is not allowed to be deferred, meaning the Company cannot give the ratepayer the benefit if it is not utilized in the current period.



With the additional tax depreciation, the Net Operating Loss (NOL) balance is now forecasted to be fully consumed by 2018 which means a NOL balance remains until 2018 and prevents the creation and usage of the Federal 199 Production Tax Deduction that was originally projected during the 2017 and 2018 plan years.



The Company had initially forecasted to use $31.4 million of 199 federal tax deductions in 2017 and $34.0 million in 2018. After the enactment of additional bonus, we are forecasting to use no deductions in 2017 and only $9.9 million in 2018. This results in an increase to the Company's request. Therefore, the impact of losing this deduction is the most significant impact of the extension of bonus.

Please see Attachments A, B, and C for bridge schedules that include all adjustments related to the PATH Act of 2015 for the 2016 Test Year, 2017 Plan Year, and 2018 Plan Year, respectively. Please note that the Bonus Tax Depreciation and Federal R&E Credit adjustments are shown in columns (2) and (3) of each page, but the impact of Secondary Calculations, especially the NOL calculation in column (6), are needed to fully illustrate the incremental impact.

Please see Attachment D for the impact of the Federal R&E credit. Row 43 of Attachment D supports the amount shown on row 41, column 3 on page 2 of each bridge schedule attachment.

Please see Attachment E for the support of the impact of the tax law changes on the interchange agreement with NSPW. Row 44 of Attachment E supports the amount shown on row 11, column 2 on page 2 of each bridge schedule attachment.

In summary, the PATH Act of 2015 cumulatively increases base rate revenue requirements for the 3 Year Plan by $4.7 million.

	2016 Test Year	2017 Plan Year	2018 Plan Year	Total
Base Rate revenue requirement impact, cumulative	$(5.4) million	$13.3 million	$4.7 million	
incremental	$(5.4) million	$18.7 million	$(8.6) million	$4.7 million

State of Minnesota, Electric Jurisdiction

However, we estimate approximately 75 percent of this increase will be offset in the Transmission Cost Recovery Rider (TCR) and the Renewable Energy Standard Rider (RES) when each rider's costs and assumptions are updated in their respective annual filings. Therefore, the total customer impact will be closer to neutral when the rate case and riders are updated and viewed collectively.

Supplemental Response:

Please see Attachments F and G to this response for bridge schedules that include all adjustments related to the PATH Act of 2015 for the 2019 and 2020 forecast years, respectively. Please note that the Bonus Tax Depreciation and Federal R&E Credit adjustments are shown in columns (2) and (3) of each page, but the impact of Secondary Calculations, especially the NOL calculation in column (6), are needed to fully illustrate the incremental impact.

$ millions	2016 Test Year	2017 Plan Year	2018 Plan Year	2019 Forecast	2020 Forecast	Total
Base Rate revenue requirement impact, cumulative	$(5.4)	$13.3	$4.7	$(9.2)	$(19.9)	
incremental	$(5.4)	$18.7	$(8.6)	$(13.9)	$(10.7)	$(19.9)

State of Minnesota, Electric Jurisdiction

The impact on the five year forecast is summarized below.

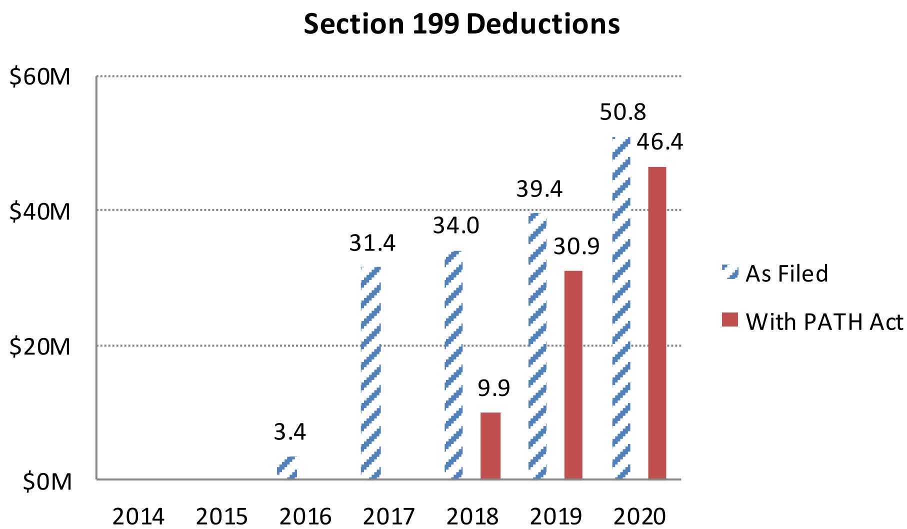
$ millions	2016 Test Year	2017 Plan Year	2018 Plan Year	2019 Forecast	2020 Forecast	Total
Burdick Sch. 13	$194.6	$246.7	$297.1	$379.6	$427.7	
PATH Act update	$(5.4)	$13.3	$4.7	$(9.2)	$(19.9)	
Updated cumulative forecast	$189.2	$260.0	$301.8	$370.4	$407.8	
incremental	$189.2	$70.8	$41.8	$68.6	$37.4	$407.8

State of Minnesota, Electric Jurisdiction

The NOL calculations provided in this supplement assume revenues equal to the Company's five-year forecast in order to solve for taxable income in each year. If the

Commission were to order different revenues, such as those in the five-year settlement offer, the NOL calculations would need to be re-solved to match.

Lastly, a revised Section 199 graph is provided below. The graph provided in the original response inadvertently excluded the change in the 2016 Section 199 amount. The graph below also provides the comparison for the 2019-2020 forecast.



Witness: Charles R. Burdick and Anne E. Heuer
Preparer: Michael Bliss
Title: Senior Rate Analyst
Department: Revenue Analysis
Telephone: 612-330-6213
Date: April 8, 2016 Supplemented: May 18, 2016

($000's)

Line No.	Description	2019 Forecast Year	Adjustment: Bonus Tax Depreciation	Adjustment: Federal R&E Credit	Secondary Calculations: ADIT Prorate for IRS	Secondary Calculations: Cash Working Capital	Secondary Calculations: Net Operating Loss	2019 Forecast Year Adjusted	Difference
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) = (7) - (1)
1	Plant as booked								
2	Production	10,301,622						10,301,622	
3	Transmission	2,885,573						2,885,573	
4	Distribution	3,658,370						3,658,370	
5	General	888,530						888,530	
6	Common	781,187						781,187	
7	Total Utility Plant in Service	18,515,282						18,515,282	
8									
9	Reserve for Depreciation								
10	Production	6,077,157						6,077,157	
11	Transmission	664,908						664,908	
12	Distribution	1,391,483						1,391,483	
13	General	451,746						451,746	
14	Common	412,713						412,713	
15	Total Reserve for Depreciation	8,998,007						8,998,007	
16									
17	Net Utility Plant								
18	Production	4,224,465						4,224,465	
19	Transmission	2,220,665						2,220,665	
20	Distribution	2,266,887						2,266,887	
21	General	436,784						436,784	
22	Common	368,473						368,473	
23	Net Utility Plant in Service	9,517,275						9,517,275	
24									
25	Utility Plant Held for Future Use								
26									
27	Construction Work in Progress	380,350						380,350	
28									
29	Less: Accumulated Deferred Income Taxes	2,412,087	321,510		(5,068)		(261,564)	2,466,964	54,877
30									
31	Other Rate Base Items								
32	Cash Working Capital	(118,076)				(574)		(118,650)	(574)
33	Materials and Supplies	135,797						135,797	
34	Fuel Inventory	73,476						73,476	
35	Non Plant Assets and Liabilities	27,456						27,456	
36	Customer Advances	(5,562)						(5,562)	
37	Customer Deposits	(28,127)						(28,127)	
38	Prepayments	85,941						85,941	
39	Regulatory Amortizations	50,579						50,579	
40	Total Other Rate Base	221,485				(574)		220,911	(574)
41									
42	Total Average Rate Base	7,707,023	(321,510)		5,068	(574)	261,564	7,651,572	(55,451)

Northern States Power Company
State of Minnesota, Electric Jurisdiction
INCOME STATEMENT ADJUSTMENT SCHEDULE
($000's)

Docket No. E002/GR-15-826
XLI Information Request No. 35 Supplement
Attachment F - Page 2 of 2

Line No.	Description	2019 Forecast Year	Adjustment: Bonus Tax Depreciation	Adjustment: Federal R&E Credit	Secondary Calculations: ADIT Prorate for IRS	Secondary Calculations: Cash Working Capital	Secondary Calculations: Net Operating Loss	Secondary Calculations: COC Change	2019 Forecast Year Adjusted	Difference
1		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9) = (8) - (1)
2	Operating Revenues									
3	Retail Revenue	3,125,156							3,125,156	
4	Interdepartmental	816							816	
5	Other Operating	639,428	(3,922)						635,506	(3,922)
6	Total Revenue	3,765,400	(3,922)						3,761,478	(3,922)
7										
8	Expenses									
9	Operating Expenses									
10	Fuel & Purchased Energy	1,125,173							1,125,173	
11	Power Production	697,081	(5,515)						691,566	(5,515)
12	Transmission	243,960							243,960	
13	Distribution	111,186							111,186	
14	Customer Accounting	50,555							50,555	
15	Customer Service and Information	91,209							91,209	
16	Sales, Econ Dev, & Other	69							69	
17	Administrative and General	224,709							224,709	
18	Total Operating Expenses	2,543,941	(5,515)						2,538,425	(5,515)
19										
20	Depreciation	612,765							612,765	
21	Amortization	21,117							21,117	
22										
23	Taxes									
24	Property	207,141							207,141	
25	Deferred Income Tax and ITC	89,250	18,886				21,302		129,438	40,188
26	Federal and State Income Tax	(66,271)	(15,506)	(3,519)	(47)	5	(20,760)	2	(106,095)	(39,824)
27	Payroll and Other	29,896							29,896	
28	Total Taxes	260,017	3,380	(3,519)	(47)	5	543	2	260,380	364
29										
30	Total Expenses	3,437,839	(2,136)	(3,519)	(47)	5	543	2	3,432,687	(5,152)
31										
32	Allowance for Funds Used During Construction	27,894							27,894	
33										
34	Total Operating Income	355,455	(1,786)	3,519	47	(5)	(543)	(2)	356,685	1,230
35										
36	Calculation of Revenue Requirements									
37	Rate Base	7,707,023	(321,510)		5,068	(574)	261,564		7,651,572	(55,451)
38	Required Operating Income	578,027	(23,599)		372	(42)	19,199	(89)	573,868	(4,159)
39	Operating Income	355,455	(1,786)	3,519	47	(5)	(543)	(2)	356,685	1,230
40	Income Deficiency	222,572	(21,813)	(3,519)	325	(37)	19,741	(86)	217,183	(5,389)
41	**Revenue Deficiency**	**379,622**	**(37,204)**	**(6,003)**	**554**	**(63)**	**33,671.096**	**(147)**	**370,430**	**(9,191)**
42										
43	Calculation of Income Taxes									
44	Operating Revenue	3,765,400	(3,922)						3,761,478	(3,922)
45	-Operating Expense	2,543,941	(5,515)						2,538,425	(5,515)
46	-Amortization	21,117							21,117	
47	-Taxes Other then Income	237,037							237,037	
48	Operating Income Before Adjs	963,306	1,594						964,899	1,594
49	Additions to Income	183,154							183,154	
50	Deductions from Income	904,088	46,276						950,364	46,276
51	Debt Synchonization	173,408	(7,202)		114	(13)	5,859	(6)	172,160	(1,248)
52	State Taxable Income	68,964	(37,481)		(114)	13	(5,859)	6	25,529	(43,435)
53	State Income Tax Before Credits	6,758	(3,673)		(11)	1	(574)	1	2,502	(4,257)
54	State Tax Credits	559							559	
55	Federal Tax Deductions	39,400					(8,476)		30,924	(8,476)
56	Federal Taxable Income	23,364	(33,807)		(102)	12	3,191	5	(7,338)	(30,703)
57	Federal Income Tax Before Credits	8,178	(11,833)		(36)	4	1,117	2	(2,568)	(10,746)
58	Federal Tax Credits	80,648		3,519			21,302		105,469	24,822
59	Total Income Taxes	(66,271)	(15,506)	(3,519)	(47)	5	(20,760)	2	(106,095)	(39,824)

Northern States Power Company
State of Minnesota, Electric Jurisdiction
RATE BASE ADJUSTMENT SCHEDULE
($000's)

Docket No. E002/GR-15-826
XLI Information Request No. 35 Supplement
Attachment G - Page 1 of 2

			Adjustment		Secondary Calculations				
Line No.	Description	2020 Forecast Year	Bonus Tax Depreciation	Federal R&E Credit	ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	2020 Forecast Year Adjusted	Difference
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) = (7) - (1)
1	Plant as booked								
2	Production	10,601,217						10,601,217	
3	Transmission	3,080,163						3,080,163	
4	Distribution	3,808,660						3,808,660	
5	General	950,675						950,675	
6	Common	849,362						849,362	
7	Total Utility Plant in Service	19,290,077						19,290,077	
8									
9	Reserve for Depreciation								
10	Production	6,518,603						6,518,603	
11	Transmission	707,809						707,809	
12	Distribution	1,452,794						1,452,794	
13	General	514,552						514,552	
14	Common	462,931						462,931	
15	Total Reserve for Depreciation	9,656,689						9,656,689	
16									
17	Net Utility Plant								
18	Production	4,082,614						4,082,614	
19	Transmission	2,372,354						2,372,354	
20	Distribution	2,355,865						2,355,865	
21	General	436,123						436,123	
22	Common	386,430						386,430	
23	Net Utility Plant in Service	9,633,387						9,633,387	
24									
25	Utility Plant Held for Future Use								
26									
27	Construction Work in Progress	435,159						435,159	
28									
29	Less: Accumulated Deferred Income Taxes	2,470,788	310,871		10,779		(180,762)	2,611,677	140,888
30									
31	Other Rate Base Items								
32	Cash Working Capital	(117,642)				(1,093)		(118,735)	(1,093)
33	Materials and Supplies	135,797						135,797	
34	Fuel Inventory	73,476						73,476	
35	Non Plant Assets and Liabilities	40,396						40,396	
36	Customer Advances	(5,562)						(5,562)	
37	Customer Deposits	(28,127)						(28,127)	
38	Prepayments	83,773						83,773	
39	Regulatory Amortizations	47,192						47,192	
40	Total Other Rate Base	229,303				(1,093)		228,210	(1,093)
41									
42	Total Average Rate Base	7,827,061	(310,871)		(10,779)	(1,093)	180,762	7,685,080	(141,982)

Northern States Power Company
State of Minnesota, Electric Jurisdiction
INCOME STATEMENT ADJUSTMENT SCHEDULE
($000's)

Docket No. E002/GR-15-826
XLI Information Request No. 35 Supplement
Attachment G - Page 2 of 2

			Adjustment		Secondary Calculations					
Line No.	Description	2020 Forecast Year	Bonus Tax Depreciation	Federal R&E Credit	ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	COC Change	2020 Forecast Year Adjusted	Difference
1		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9) = (8) - (1)
2	Operating Revenues									
3	Retail Revenue	3,233,276							3,233,276	
4	Interdepartmental	847							847	
5	Other Operating	669,017	(3,427)						665,590	(3,427)
6	Total Revenue	3,903,140	(3,427)						3,899,712	(3,427)
7										
8	Expenses									
9	Operating Expenses									
10	Fuel & Purchased Energy	1,248,543							1,248,543	
11	Power Production	707,601	(5,008)						702,593	(5,008)
12	Transmission	255,579							255,579	
13	Distribution	112,100							112,100	
14	Customer Accounting	51,413							51,413	
15	Customer Service and Information	91,241							91,241	
16	Sales, Econ Dev, & Other	69							69	
17	Administrative and General	228,312							228,312	
18	Total Operating Expenses	2,694,858	(5,008)						2,689,850	(5,008)
19										
20	Depreciation	643,851							643,851	
21	Amortization	17,523							17,523	
22										
23	Taxes									
24	Property	209,086							209,086	
25	Deferred Income Tax and ITC	(2,422)	(40,162)				140,303		97,719	100,141
26	Federal and State Income Tax	3,793	44,249	(3,519)	100	10	(140,407)	23	(95,751)	(99,544)
27	Payroll and Other	30,496							30,496	
28	Total Taxes	240,953	4,087	(3,519)	100	10	(104)	23	241,550	597
29										
30	Total Expenses	3,597,186	(921)	(3,519)	100	10	(104)	23	3,592,775	(4,411)
31										
32	Allowance for Funds Used During Construction	32,677							32,677	
33										
34	Total Operating Income	338,631	(2,506)	3,519	(100)	(10)	104	(23)	339,614	984
35										
36	Calculation of Revenue Requirements									
37	Rate Base	7,827,061	(310,871)		(10,779)	(1,093)	180,762		7,685,080	(141,982)
38	Required Operating Income	589,378	(22,818)		(791)	(80)	13,268	(270)	578,687	(10,691)
39	Operating Income	338,631	(2,506)	3,519	(100)	(10)	104	(23)	339,614	984
40	Income Deficiency	250,747	(20,312)	(3,519)	(691)	(70)	13,164	(246)	239,072	(11,675)
41	**Revenue Deficiency**	**427,677**	**(34,644)**	**(6,003)**	**(1,179)**	**(120)**	**22,453**	**(420)**	**407,764**	**(19,913)**
42										
43	Calculation of Income Taxes									
44	Operating Revenue	3,903,140	(3,427)						3,899,712	(3,427)
45	-Operating Expense	2,694,858	(5,008)						2,689,850	(5,008)
46	-Amortization	17,523							17,523	
47	-Taxes Other then Income	239,582							239,582	
48	Operating Income Before Adjs	951,176	1,581						952,757	1,581
49	Additions to Income	188,486							188,486	
50	Deductions from Income	813,150	(98,414)						714,736	(98,414)
51	Debt Synchonization	178,457	(6,964)		(241)	(24)	4,049	(57)	175,220	(3,237)
52	State Taxable Income	148,056	106,958		241	24	(4,049)	57	251,288	103,232
53	State Income Tax Before Credits	14,509	10,482		24	2	(397)	6	24,626	10,117
54	State Tax Credits	559							559	
55	Federal Tax Deductions	50,840					(4,489)		46,351	(4,489)
56	Federal Taxable Income	83,265	96,476		218	22	837	51	180,870	97,605
57	Federal Income Tax Before Credits	29,143	33,767		76	8	293	18	63,304	34,162
58	Federal Tax Credits	39,300		3,519			140,303		183,122	143,822
59	Total Income Taxes	3,793	44,249	(3,519)	100	10	(140,407)	23	(95,751)	(99,544)

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

Xcel Energy			
Docket No.:	E002/GR-15-826		
Response To:	Department of Commerce	Information Request No.	157
Requestor:	Nancy Campbell, Angela Byrne, Dale Lusti		
Date Received:	March 17, 2016		**SUPPLEMENT**

Question:

Reference: FERC December 30, 2015 Order in Docket No. ER16-197
Subject: Denial of Accumulated Deferred Income Tax True-Up

In FERC's December 2015 Order, FERC rejected NSP's Accumulated Deferred Income Tax True-up and required NSP to remove the IRS pro-rated tax calculation to their annual true-up and provide a true-up calculation that continues to support beginning-of-year and end-of-year balances for ADIT accounts in NSP's Attachment O. Note FERC accepted Otter Tail Power and Minnesota Powers proposals to continue to use beginning and end-of-year balances for ADIT accounts. As a result, please explain why NSP should not be required to use beginning-of-year and end-of-year ADIT balances for true-up purposes for the following year (for example true-up of 2016 TY ADIT balances in 2017) in this rate case?

Response:

Subsequent to the FERC December Order in Docket ER16-197, on March 11, 2016, Ameren Illinois, Ameren Transmission Company of Illinois, and both NSP Companies (NSPM and NSPW) moved to lodge in Docket No. ER16-197-000 the Order on Revised ADIT Treatment, issued by the FERC on February 23, 2016 in Docket No. ER14-1831-001. The motion states the following:

> The *Order on Revised ADIT Treatment* is directly relevant to the issues in Docket No. ER16-197 because it concerns the application of the proration methodology described in Section 1.167(l)-1(h)(6)(ii) of the Treasury regulations. Specifically, in the *Order on Revised ADIT Treatment*, the Commission accepted the proposal of Virginia Electric and Power Company, doing business as Dominion Virginia Power ("Dominion") to continue to apply the proration methodology to the originally projected Accumulated Deferred Income Tax ("ADIT") balances in performing the

> annual true-up calculations. In the Commission's December 30, 2015 order in the captioned proceeding, the Commission rejected Ameren's and the NSP Companies' similar proposals to continue to apply the proration methodology to the originally projected ADIT balances in performing the annual formula rate true-up calculations. Indicated Transmission Owners therefore also move for reconsideration of the December 2015 Order, pursuant to Rule 212 of the Commission's Rules of Practice and Procedure.

Thus the Company believes that proration for ADIT is necessary in the capital true up in order to not violate normalization rules and that it should be done with the same method allowed by the FERC for Dominion. We further believe that proration is necessary for any forward looking rate making and subsequent true up. The true up calculation would be performed so as to preserve the effect of the proration used in the forecasted test year calculation. To the extent that the actual annual change in ADIT balance is greater than the forecasted annual change in ADIT balance, the difference between the two balances would not be prorated and the difference would be added to the originally calculated ADIT amount. In the event that the actual annual change in ADIT balance was less than the forecasted annual change in ADIT balance, then the entire change between beginning and ending ADIT balance is prorated and averaged. For further support for this position, we have attached the motion as Attachment A and the information also can be found at the following link:

http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20160311-5226

Supplement:

Included as Attachment A to this response is the FERC Order, issued April 12, 2016, for the PSCo and SPS formula rates in Docket Nos. ER16-236 and ER16-239. The PSCo and SPS formula rates use proration for the calculation of ADIT in the forecast and the true-up. The proration was approved by the FERC for ADIT true-up in line with the method that was approved for Dominion.

Witness:	Lisa H. Perkett	
Preparer:	Lisa H. Perkett	
Title:	Director	
Department:	Capital Asset Accounting	
Telephone:	(612) 330-6950	
Date:	March 29, 2016	**Supplemented: April 15, 2016**

155 FERC ¶ 61,028
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, and Colette D. Honorable.

Public Service Company of Colorado Docket Nos. ER16-236-000
ER16-236-001
ER16-239-000
ER16-239-001

ORDER ACCEPTING REVISIONS TO FORMULA RATES, SUBJECT TO CONDITION

(Issued April 12, 2016)

1. On November 2, 2015, pursuant to section 205 of the Federal Power Act (FPA),[1] Public Service Company of Colorado (PSCo), on behalf of itself and its affiliate Southwestern Public Service Company (SPS), submitted proposed revisions to the transmission formula rates for PSCo and SPS included in the Xcel Energy Operating Companies' FERC Electric Tariff (Xcel Energy Tariff). Also on November 2, 2015, PSCo submitted proposed revisions to its production formula rate included in its Assured Power and Energy Requirements Service Tariff (Production Tariff). PSCo proposes these revisions in order to comply with section 1.167(l)-1(h)(6)(ii) of the United States Internal Revenue Service (IRS) regulations.[2] In this order, we accept the proposed revisions, effective January 1, 2016, as requested, subject to condition, and direct a compliance filing.

[1] 16 U.S.C. § 824d (2012).

[2] Treas. Reg. § 1.167(l)-1(h)(6)(ii) (as amended in 1974).

I. **Background**

2. Under Commission ratemaking policies, income taxes included in rates are determined based on the return on net rate base calculated using straight-line depreciation.[3] However, in calculating the actual amount of income taxes due to the IRS, companies generally are able to take advantage of accelerated depreciation. Accelerated depreciation will usually lower income taxes payable during the early years of an asset's life followed by corresponding increases in income taxes payable during the later years of an asset's life. This means that a company's income taxes payable to the IRS during a period will differ from its income tax expenses for ratemaking purposes during the same period. The difference between the income taxes based on straight-line-depreciation and the actual income taxes paid by the company are reflected in an account called Accumulated Deferred Income Taxes (ADIT).[4] Because the resulting ADIT effectively provides the company with cost-free capital, the Commission subtracts the ADIT from the company's rate base, thereby reducing customer charges. This method of passing the benefits from accelerated depreciation on to ratepayers throughout the asset's life is referred to as tax normalization.

3. The depreciation normalization rules of the Internal Revenue Code (Normalization Rules) mandate the use of a very specific proration procedure in measuring the amount of future test period ADIT that can reduce rate base. Section 1.167(l)-1(h)(6)(ii) of the IRS regulations requires that, if a utility uses solely a future period (projected test year) to determine depreciation, "the amount of the reserve account for the period is the amount of the reserve at the beginning of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during such period." The pro rata amount of any increase during the future portion of the period is determined by multiplying the increase by a fraction, the numerator of which is the number of days remaining in the period at the time the increase is to accrue, and the denominator of which is the total number of days in the future portion of the period.[5] The purpose of the

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[3] *See, e.g., PJM Interconnection, L.L.C. and Va. Elec. and Power Co.*, 147 FERC ¶ 61,254, *order on compliance*, 154 FERC ¶ 61,126, at P 2 (2016) (*Virginia Electric*).

[4] There are four categories of ADIT recognized in the Uniform System of Accounts in four separate accounts; however, only three of these categories of ADIT are related to accelerated depreciation, including bonus depreciation: Accounts 190, Accumulated Deferred Income Taxes; 281, Accumulated Deferred Income Taxes-Accelerated Amortization Property; and 282, Accumulated Deferred Income Taxes-Other Property.

[5] Treas. Reg. § 1.167(l)-1(h)(6)(ii) (as amended in 1974).

proration requirement is to prevent the immediate flow-through of the benefits of accelerated depreciation to ratepayers, allowing funds provided by accelerated depreciation to be used for investments.

4. The IRS requires utilities to follow its regulations in order to take advantage of accelerated depreciation. Certain electric utilities have requested revenue rulings from the IRS regarding the calculation of ADIT for formula rates, which include a projection of expected investments for the coming year. These formula rates also include a true-up mechanism through which the utility calculates adjustments to its formula, for example, for the differences from investments that did not occur when projected.

II. PSCo's Filings

5. In Docket No. ER16-236-000, PSCo states that it is filing revisions to the Xcel Energy Tariff to modify the manner by which PSCo and SPS will calculate average ADIT balances within their transmission formula rates in order to comply with section 1.167(l)-1(h)(6)(ii) of the IRS regulations.[6] PSCo also filed proposed revisions to its Production Tariff in Docket No. ER16-239-000 to effectuate similar changes to the ADIT provisions within its production formula rate.[7] PSCo notes that SPS is not proposing to modify its production formula rates at this time.[8]

6. PSCo states that, in a series of private letter rulings (PLR), the IRS has found that, for a utility that uses a projected test year to claim accelerated depreciation for utility plant in its income tax filings, the utility must use the formula provided in section 1.167(1)-1(h)(6)(ii) of the IRS regulations to calculate the amount of deferred income taxes subject to exclusion from the rate base.[9] PSCo notes that the IRS has indicated that utilities subject to this requirement that do not seek to comply are subject to

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[6] PSCo, Docket No. ER16-236-000, Transmittal at 1.

[7] PSCo, Docket No. ER16-239-000, Transmittal at 1.

[8] PSCo, Docket No. ER16-236-000, Transmittal at 4 n.13.

[9] *Id*. at 3; PSCo, Docket No. ER16-239-000, Transmittal at 3 (citing Exh. III, I.R.S. Priv. Ltr. Rul. 143241-14 (Jul. 6, 2015); I.R.S. Priv. Ltr. Rul. 140120-14 (Apr. 14, 2015)).

the sanction of denial of accelerated depreciation,[10] which would cause a significant increase in rate base and rates.[11]

7. PSCo states that PSCo and SPS calculate their annual transmission revenue requirements pursuant to the formulae set forth in Attachment O-PSCo and Attachment O-SPS of the Xcel Energy Tariff, respectively.[12] According to PSCo, both companies employ a forward-looking Attachment O, and each submits an annual informational filing with the Commission that consists of the true-up for the prior period actuals and the estimated rates for the upcoming rate year. PSCo states that it proposes to revise the Attachment O of each company to provide that the calculation of ADIT for both the annual projection and true-up will be performed in accordance with section 1.167(l)-1(h)(6) of the IRS regulations. Therefore, PSCo states that it proposes to include a new work paper (WP ADIT Prorate) in each Attachment O in the Xcel Energy Tariff, which calculates the proration factor according to the IRS regulations, and additional revisions and additions to existing work papers that describe how PSCo and SPS will calculate ADIT balances for both the projected test year revenue requirement and the annual true-up using the proration methodology required by the IRS.[13] PSCo further notes that the revisions included in the work papers maintain PSCo's and SPS's use of beginning of year and end of year ADIT balances, which is consistent with Commission requirements.[14]

8. PSCo states that it calculates its production rates pursuant to the forward-looking formulae set forth in Attachment A of its Production Tariff, and that it uses projected or estimated data to set its production rates, in conjunction with a process that trues up the rate based on actual data.[15] Therefore, similar to the proposed revisions in PSCo's and SPS's transmission formula rates, PSCo proposes to revise ADIT-related work papers in

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[10] PSCo, Docket No. ER16-236-000, Transmittal at 3-4; PSCo, Docket No. ER16-239-000, Transmittal at 3.

[11] PSCo, Docket No. ER16-236-000, Transmittal at 6; PSCo, Docket No. ER16-239-000, Transmittal at 5.

[12] PSCo, Docket No. ER16-236-000, Transmittal at 2.

[13] *Id*. at 4.

[14] *Id*. at 4-5 (citing 18 C.F.R. § 35.13(h)(6) (2015)).

[15] PSCo, Docket No. ER16-239-000, Transmittal at 2.

Attachment A by adding a new work paper (WP ADIT Prorate) to provide that the calculation of ADIT for both the annual projected revenue requirement and the true-up for its production formula rate will be performed in accordance with section 1.167(l)-1(h)(6) of the IRS regulations.[16] PSCo also notes that its revisions maintain the use of beginning of year and end of year ADIT balances.[17]

9. According to PSCo, using the proration formula increases PSCo's estimated 2016 annual transmission revenue requirement by $579,000, which represents a 0.2 percent increase over its $244 million revenue requirement. Similarly, PSCo states that the use of the proration formula increases SPS's estimated 2016 annual transmission revenue requirement by $416,000, which represents a 0.3 percent increase over its $129 million revenue requirement. With regard to PSCo's production formula rate, PSCo notes that use of the proration formula increases PSCo's estimated 2016 production revenue requirement by $102,000, which is a 0.1 percent increase above the total production revenue requirement of $81.7 million. PSCo states that, due to the timing of when it became aware of the need to revise the formula rates, PSCo's and SPS's 2016 estimates did not reflect the new ADIT proration formula. However, PSCo notes that it and SPS have notified customers of the need to modify the formula rates and that, before the end of 2015, it and SPS will provide customers with updated transmission and production formulas and associated work papers that reflect the incorporation of the proration formula.[18]

10. In addition to the ADIT-related revisions requested in Docket No. ER16-236-000, PSCo also proposes tariff revisions in SPS's Attachment O Tables 6 and 11 to reflect revisions agreed to as part of a recent settlement agreement in Docket No. EL05-19-000.[19] PSCo notes that SPS will be submitting compliance filings to implement the revisions agreed upon in the settlement proceeding, to be effective on January 1, 2015, but that, in order to avoid a circumstance where the eTariff records related to the instant proceeding (effective January 1, 2016) do not include the settlement agreement revisions to Table 6

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[16] *Id*. at 4.

[17] *Id*. (citing 18 C.F.R. § 35.13(h)(6) (2015)).

[18] PSCo, Docket No. ER16-236-000, Transmittal at 6-7; PSCo, Docket No. ER16-239-000, Transmittal at 5-6.

[19] *See Golden Spread Elec. Coop. Inc. v. Sw. Pub. Serv. Co.*, 153 FERC ¶ 61,103 (2015) (*Golden Spread*).

and 11, SPS is including such revisions as part of the tariff changes proposed in the instant proceeding.[20]

III. Notice and Responsive Pleadings

11. Notice of PSCo's filing in Docket No. ER16-236-000 was published in the *Federal Register*, 80 Fed. Reg. 69,212 (2015), with interventions and protests due on or before November 23, 2015. On November 23, 2015, Golden Spread Electric Cooperative (Golden Spread) filed a timely motion to intervene and an unopposed request for limited extension of comment date, which the Commission granted. On November 30, 2015, Golden Spread filed a limited protest and request for hearing and settlement judge procedures. On December 11, 2015, Tri-State Generation and Transmission Association (Tri-State), Intermountain Rural Electric Association (IREA), and Holy Cross Electric Association (Holy Cross) filed a joint motion to intervene out-of-time. On December 15, 2015, Xcel Energy Services Inc. (Xcel Energy) filed an answer to Golden Spread's protest.

12. Notice of PSCo's filing in Docket No. ER16-239-000 was published in the *Federal Register*, 80 Fed. Reg. 69,212 (2015), with interventions and protests due on or before November 23, 2015. On December 11, 2015, Tri-State, IREA, and Holy Cross filed a joint motion to intervene out-of-time.

13. On December 23, 2015, Commission staff advised PSCo that its filings were deficient and additional information would be necessary to evaluate its submissions.[21] On January 21, 2016, Xcel Energy, on behalf of PSCo, requested an extension of time for the filing of its response, which the Commission granted. On February 12, 2016, PSCo filed its response.

14. Notice of PSCo's Deficiency Response was published in the *Federal Register*, 81 Fed. Reg. 8954 (2016), with interventions and comments due on or before March 4, 2016. On March 4, 2016, Golden Spread filed a protest to the Deficiency Response and renewed request for hearing and settlement judge procedures. On March 21, 2016, Xcel Energy filed an answer to Golden Spread's protest.

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[20] PSCo, Docket No. ER16-236-000, Transmittal at 5-6.

[21] *Pub. Serv. Co. of Colo.*, Deficiency Letter, Docket No. ER16-236-000, *et al.*, at 1 (issued Dec. 23, 2015) (Deficiency Letter).

A. Golden Spread Protest

15. Golden Spread notes that it is not a transmission customer of PSCo, and therefore, protests the proposed changes in Docket No. ER16-236 solely as they relate to the transmission rates of SPS.[22] Golden Spread asserts that it has identified four errors with PSCo's proposal for SPS.[23] First, Golden Spread claims that, after SPS performs its proration calculation, it takes the extra step of averaging the beginning and ending balance, which has the undesired consequence of cutting the calculated proration in half, from 53.78 percent to 26.89 percent. Second, and related to the first error, Golden Spread argues that, when SPS carries the calculated proration amount in column (f) to the next column of Worksheet D, it performs an extra calculation that once again skews the appropriate IRS-compliant prorated balance that SPS should use as an average rate base balance in projected formula rates.[24] Using Account 281 from Worksheet D of the 2016 SPS Projection as an example, Golden Spread states that the effect of these first two errors results in a calculated projected average balance with an ADIT proration of -$1,635,436.[25] Golden Spread contends that the correct projected average balance with an ADIT proration that complies with the IRS regulations should be -$1,723,515.[26]

16. Third, Golden Spread states that it appears that SPS intends to create an ADIT proration for the true-up component of the formula rate as well.[27] According to Golden Spread, while PSCo and SPS have not sought their own PLRs from the IRS, guidance found in a PLR attached as Exhibit III to the PSCo and SPS filing directly contradicts the proposed tariff changes, and, therefore, columns (k), (l), (m), and (n) of Worksheet D of SPS's transmission formula rate should be removed and replaced with a

[22] Golden Spread Limited Protest at 2 & n.4.

[23] *Id*. at 4 (citing Attachment 1 (Worksheet D)).

[24] *Id*. (citing Attachment 1 (Worksheet D, column (g))).

[25] *Id*. at 5.

[26] *Id*.

[27] *Id*. at 6 (citing Attachment 1 (Worksheet D, columns (k), (l), (m), (n))).

column representing the existing practice of calculating an average beginning of year and end of year balance for the purposes of the true-up calculation.[28]

17. Finally, Golden Spread notes that SPS's proposed tariff changes lack sufficient detail to differentiate between those account balances to which it must apply a proration to comply with IRS regulations and those for which it should continue to use a simple average of beginning and year end projected balances in Worksheet D average rate base calculations of the SPS formula.[29] Golden Spread argues that SPS should be directed to clarify on Worksheet D of its transmission formula rate that only items that are subject to IRS regulations addressing accelerated depreciation should be subject to any application of a proration in the projected rate columns.

18. Golden Spread believes that a nominal suspension is appropriate, such that SPS's rates may become effective subject to refund on January 1, 2016.[30] To the extent that the Commission does not summarily require correction of the formula rate in its order, Golden Spread requests that the Commission set the issues associated with SPS's proration process for hearing and hold the hearing in abeyance, pending the outcome of the *Virginia Electric*[31] proceeding and/or the issuance of industry-wide guidance by the Chief Accountant on this topic.[32]

B. Xcel Energy Answer

19. Xcel Energy contends that the use of the proration formula in conjunction with beginning of year and end of year averaging is necessary to meet the IRS's normalization requirements.[33] Xcel Energy asserts that a purpose of the calculations in Worksheet D and

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[28] *Id*. at 7 (citing PSCo and SPS Filing, Docket No. ER16-236-000, *et al*., Exh. III (I.R.S. Priv. Ltr. Rul. 143241-14 at 12) and noting that the private letter ruling offered by PSCo and SPS is not binding precedent).

[29] *Id*. at 7-8.

[30] *Id*. at 10.

[31] *See Virginia Electric*, 154 FERC ¶ 61,126.

[32] Golden Spread Limited Protest at 3 (citing *Virginia Electric*, 147 FERC ¶ 61,254 at P 18), 10-11.

[33] Xcel Energy December 15 Answer at 8.

D.2 is to continue compliance with Commission policy to create an average balance for ADIT, and that, as a result of that policy, the calculations in question are therefore necessary to maintain compliance with the IRS's consistency rule. Xcel Energy notes that the IRS concluded that "[f]ailure to average the deferred tax reserve, as prorated, before excluding the reserve from the average rate base will violate the consistency requirement of section 168(i)(9)(B)."[34] Xcel Energy argues that Golden Spread relies on an unsupported and unexplained presumption that proration serves the same function as the beginning of year and end of year averaging, which has been contradicted by the IRS in multiple PLRs.[35]

20. Xcel Energy states that the true-up process cannot be used to unwind the proration calculation of ADIT. According to Xcel Energy, the IRS's view is that forward-looking formula rates with true-up procedures employ a future test period subject to normalization requirements, and such formula rates must use the proration formula in estimating ADIT amounts, including carrying forward the amounts of ADIT calculated using the proration formula into the true-up. Xcel Energy asserts that the IRS has stated that, "[i]n calculating the true-up, proration applies to the original projection amount,"[36] and notes that the originally projected amount is thus carried forward into the true-up, and therefore is not "unwound" by reversing the proration calculation.[37] Xcel Energy explains that the true-up component is determined by reference to a purely historical period and that there is no need to use the proration formula to calculate the differences between projected and actual balances. Xcel Energy contends that Golden Spread's argument would result in a true-up process that reverses the original proration calculation.

21. Xcel Energy asserts that the proration calculation must be applied to appropriate amounts in Account 190 estimated for the projected year. Xcel Energy maintains that deferred tax asset related to the net operating loss in Account 190 is inextricably related to accelerated depreciation, including bonus depreciation,[38] and that the only proposed change related to Account 190 balances in the instant filings is to incorporate the proration

[34] *Id*. at 9 (citing I.R.S. Priv. Ltr. Rul. 9202029 (Oct. 15, 1991)).

[35] *Id*. at 9-10 (citing I.R.S. Priv. Ltr. Rul. 9202029; I.R.S. Priv. Ltr. Rul. 9224040 (June 12, 1992); I.R.S. Priv. Ltr. Rul. 9313008 (December 17, 1992)).

[36] *Id*. at 11 (citing I.R.S. Priv. Ltr. Rul. 143241-14 at 8).

[37] *Id*. at 12.

[38] *Id*. at 13.

calculation into the projections of these ADIT balances, which is done annually under the SPS transmission formula rate. Xcel Energy states that SPS believes it is reasonable to include all plant-related deferred tax balances used in the determination of rate base when it applies the proration due to the overall lower rates for customers that result. In response to Golden Spread's argument concerning lack of clarity in which Account 190 balances will be subject to proration, Xcel Energy notes that SPS is willing to submit further revisions to its Attachment O to include a footnote stating that "[p]roration is applied to plant related items impacted by Internal Revenue Service rules governing tax normalization."[39]

22. Xcel Energy also notes that the Commission's policy is to set a filing for hearing and settlement judge procedures where the filing raises an issue of material fact that cannot be resolved based on pleadings before the Commission, and, even where there are disputed issues, the Commission need not conduct such a hearing if the issues may be adequately resolved based on the written record.[40] Xcel Energy asserts that the issues raised by Golden Spread concern the proper legal interpretation of IRS regulations, not a material fact that is in dispute between the parties, and therefore neither a hearing nor settlement judge procedures is appropriate. Xcel Energy states that the differences in Xcel Energy's and Golden Spread's positions turn on interpretations of the IRS's requirements, and at stake is the continued eligibility of SPS to use accelerated depreciation.

IV. Deficiency Letter, Response, and Related Pleadings

23. In the Deficiency Letter, Commission staff requested information to aid the Commission in evaluating PSCo's proposed revisions to comply with the IRS regulations by modifying how ADIT is calculated in its transmission and production formula rates. Commission staff requested that PSCo demonstrate the calculation of ADIT using the proration formula for both the estimated amounts of the annual projection and the actual amounts, explain how revising the calculations to conform to IRS regulations is also consistent with the formulas' existing use of average ADIT balances, explain why calculating an ADIT proration factor based on monthly balances is more appropriate than calculating an ADIT proration factor based on daily balances, and explain why the tariff

[39] *Id.* at 14-15.

[40] *Id*. at 16.

revisions contemplated within PSCo's settlement agreement should be accepted within the context of this proceeding.[41]

24. In its Deficiency Response, PSCo submitted hypothetical, illustrative calculations with additional revisions, including changes to the descriptive titles of columns (k), (l), (m), and (n) of the true-up section of Table 8, Workpaper B-2,[42] and revisions to Footnotes 5 and 6 of this section to clarify that PSCo is not proposing to apply the proration calculation to the difference between forecasted and actual amounts.[43] PSCo states that the revisions do not change the intent of the originally-proposed method of calculating the true-up, and that the revised tariff records submitted with the response make corresponding changes to the SPS transmission formula template (Attachment O-SPS) and the PSCo production template. In addition, PSCo also submitted revisions to address Golden Spread's assertions regarding the perceived lack of clarity in which Account 190 balances will be subject to the proration calculation by incorporating an additional footnote into SPS's transmission formula rate template, as discussed in Xcel Energy's Answer.[44]

25. In response to staff's question regarding averaging, PSCo references section 1.167(1)-1(h)(6) of the IRS regulations that requires usage of a proration formula in determining projected ADIT amounts for rate calculation purposes in future test periods, and the "consistency requirement" in Internal Revenue Code section 168(i)(9)(B) that requires application of averaging to the ADIT amounts calculated through proration if the ratemaking methodology employs averaging.[45] PSCo states that the IRS has explained that the proration calculation serves a different purpose than the averaging used in the rate design methodology, and therefore, they are not duplicative calculations. PSCo asserts that the IRS's view on this matter is unambiguous, and has been confirmed on multiple occasions.[46]

[41] *Pub. Serv. Co. of Colo.,* Deficiency Letter, Docket No. ER16-236-000, *et al.,* at 1 (issued Dec. 23, 2015) (Deficiency Letter).

[42] Deficiency Response at 2.

[43] *Id*. at 3.

[44] *Id.*

[45] *Id*. at 4.

[46] *Id*. at 5 & n.6.

26. PSCo notes that Commission policy requires the use of an average rate base in the calculation of rates, and the Commission's regulations state that ADIT should be calculated as the average of the beginning and end of test year balances.[47] PSCo states that its and SPS's formula rates already reflect the use of beginning and end of test year balances. According to PSCo, in order to comply with both the consistency and proration requirements, PSCo and SPS must apply the beginning-of-year and end-of-year averaging.

27. In response to staff's question on the appropriateness of calculating the proration factor based on monthly balances verses daily balances, PSCo notes that the proration factor for its plant and SPS's plant is calculated based on monthly balances, as required by the Commission's regulations. PSCo asserts that the IRS consistency rules require the calculation of associated ADIT to be consistent, and, therefore, the ADIT proration factor must be based on monthly balances. PSCo states that, since its and SPS's plant is not calculated based on daily balances, calculating the ADIT proration factor based on daily balance would not meet the consistency requirement, and thus PSCo and SPS would not be in compliance with the IRS normalization rules.[48]

28. In response to Commission staff's question on SPS's settlement agreement, PSCo clarifies that revisions to Tables 6 and 11 of Attachment O-SPS contemplated in the settlement agreement in Docket No. EL05-19-000 are not related to ADIT. PSCo explains that the settlement agreement revisions to Note K on Tables 6 and 11 relate to Postretirement Benefits Other Than Pensions expense. PSCo notes that the settlement agreement contained pro forma tariff sheets that included revisions to Tables 6 and 11 of Attachment O-SPS, with an effective date of January 1, 2015, thus predating the revisions proposed in this proceeding.[49]

29. In response, Golden Spread states that it can accept SPS's preferred proration methodology in the projection as an alternative methodology that satisfies the goals of the IRS regulations, but only if SPS calculates the true-up correctly.[50] Golden Spread observes that it and the Commission raised concerns with SPS's proposal to apply a proration in the true-up, notwithstanding the fact that the true-up is performed in a subsequent rate year and

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[47] 18 C.F.R. § 35.13(h)(6) (2015).

[48] Deficiency Response at 8.

[49] *Id*. at 9.

[50] Golden Spread Protest to Deficiency Response at 3 (citing PSCo and SPS Filing, Docket No. ER16-236-000, *et al*., Exh. III (I.R.S. Priv. Ltr. Rul. 143241-14 at 4, 8, 11)).

based on historical, audited data.[51] Golden Spread argues that SPS has not changed this aspect of its rate change proposal and that the continued misapplication of the IRS regulations and PLR guidance results in SPS's proffered formula rate true-up mechanism substantially understating the true-up in a manner that harms customers.[52] Golden Spread states that, under SPS's hypothetical example, the projection in both scenarios would yield a value of $311,555,100.[53] Thus, Golden Spread further points out, SPS would calculate the true-up to yield a value of $349,055,100, or a variance of $37,055,100 from the projection. Under Golden Spread's proposed corrections, the true-up would now yield a value of $362,500,000, or a variance of $50,944,900.[54] Therefore, Golden Spread contends that, if SPS is permitted to prorate the true-up, customers would receive $13.4 million less in credit to rate base. Golden Spread asserts that SPS's proposed Worksheet D amendments are not just and reasonable and are unduly discriminatory and preferential.

30. In its March 21 Answer, Xcel Energy contends that Golden Spread's suggestion in its Limited Protest that the Commission could consider holding this proceeding in abeyance pending the outcome of *Virginia Electric* has been effectively met. Xcel Energy states that, in *Virginia Electric*, the Commission accepted the proposed true-up methodology, which is the same as the methodology proposed in PSCo's filings, and rejected customers' arguments, which were the same arguments raised by Golden Spread.[55] Xcel Energy, however, notes two points in *Virginia Electric* not illustrated in PSCo's and SPS's true-up calculations: (1) when actual ADIT activity is less than projected ADIT activity, but still represents an overall increase in ADIT, the projected ADIT amount would be decreased in the formula rate by the difference between the projected and actual ADIT amounts; and (2) when actual ADIT activity is less than projected ADIT activity, and represents an overall decrease in ADIT, the formula would use the actual decrease in the ADIT value instead of the originally-projected ADIT

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[51] *Id*. at 4 (citing Deficiency Letter, Question 1).

[52] *Id*. (citing SPS Worksheet D, Table 19).

[53] *Id*. at 5-8.

[54] *Id*.

[55] Xcel Energy March 21 Answer at 3-4.

amount.[56] Xcel Energy states that PSCo and SPS commit to revise their formula rate templates to incorporate these additional steps upon direction of the Commission.

V. Discussion

A. Procedural Matters

31. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2015), the timely, unopposed motion to intervene of Golden Spread in Docket No. ER16-236 serves to it a party to that proceeding. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2015), we grant Tri-State's, IREA's, and Holy Cross's joint motions to intervene out-of-time in Docket Nos. ER16-236 and ER16-239 given their interests in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay.

32. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R § 385.213(a)(2) (2015), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We accept Xcel Energy's answers because they have provided information that assisted us in our decision-making process.

B. Substantive Matters

33. We find that PSCo's proposed tariff revisions represent a method of compliance with IRS regulations given their current rulings, and we will accept PSCo's filings, subject to the condition that PSCo submit revisions to PSCo's and SPS's formula rate templates, as discussed below.[57] In recent orders, the Commission has clarified that, when a section 205 filing is strictly limited to tax matters, the Commission will base its evaluation on whether "the proposed revisions are reasonable to comply with IRS regulations,"[58] and has

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[56] *Id.* at 4-5.

[57] The Commission can revise a proposal filed under section 205 of the FPA as long as the filing utility accepts the change. *See City of Winnfield v. FERC*, 744 F.2d 871, 875-77 (D.C. Cir. 1984). The filing utility is free to indicate that it is unwilling to accede to the Commission's conditions by withdrawing its filing.

[58] *See, e.g., Midcontinent Indep. Transmission Operator, Inc.*, 153 FERC ¶ 61,371, at P 36 (2015) (*MISO*).

expressly rejected the "objection that Private Letter Rulings issued by the IRS cannot be a basis for [] proposed rate revisions."[59]

34. Despite Golden Spread's protests that certain proposed calculations in SPS's Worksheet D unnecessarily average the prorated account balance, and that the initial proration factor creates the average that should be used to comply with IRS regulations, we find that PSCo's methodology is reasonable. PSCo's proposal determines the average rate base by taking the average net plant and subtracting an average of ADIT values. As the IRS indicated in a PLR, "[w]hile there are minor differences in the convention used to average all elements of rate base including depreciation expense on the one hand, and [ADIT] on the other . . . it is sufficient that both are determined by averaging and both are determined over the same period of time."[60] We find that this interpretation also is consistent with the interpretation of other utilities applying the IRS regulations regarding proration.[61]

35. In addition, we dismiss Golden Spread's related protest that SPS performs extra calculations in Worksheet D that skew the appropriate IRS-compliant prorated balance.[62] While Golden Spread makes clear the distinction between how it interprets the method for calculating the average prorated balance and how such a calculation would be made under the proposed tariff revisions for SPS, Golden Spread has not demonstrated that the method proposed by SPS is inconsistent with IRS regulations. In addition, PSCo demonstrates through a hypothetical population that calculating an average prorated balance through an alternative, monthly approach results in the same answer as calculating the average prorated balance through the template method proposed in its tariff revisions.[63] Therefore, we find that PSCo's proposed method for calculating the average ADIT balance is reasonable to comply with the IRS regulations.

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[59] *Id*. P 40.

[60] PSCo, Docket No. ER16-236-000, Transmittal at 3 (citing I.R.S. Priv. Ltr. Rul. 143241-14 at 10).

[61] *See, e.g.*, *Virginia Electric*, 154 FERC ¶ 61,126; *MISO*, 153 FERC ¶ 61,371.

[62] *See* Golden Spread Limited Protest at 4-6.

[63] Deficiency Response at 6-7.

36. While Golden Spread objects to PSCo's proposal to apply the IRS's proration methodology for the originally-projected ADIT amount within the true-up calculation, we also find that this treatment is reasonable to comply with IRS regulations. As the IRS indicated in the PLR included with PSCo's filing, "in calculating the true-up, proration applies to the original projection amount but the actual amount added to the [ADIT] over the test year is not modified by application of the proration formula."[64] Golden Spread's contention that the proposed tariff amendments to the SPS transmission formula rate contradict IRS guidance and harm customers is grounded in an alternative interpretation of language in the cited PLR. However, the fact that the relevant language in the PLR might be susceptible to an alternative interpretation alone does not discount the reasonableness of the interpretation offered by PSCo. Based on the record in this proceeding, we find PSCo's proposed methodology for applying the proration formula to the true-up calculation to be consistent with the methodology approved in *Virginia Electric,* and a reasonable interpretation of the PLR.[65] If the IRS issues further clarifying guidance, it may be considered in future Commission decisions.

37. Further, while we find that PSCo's proposal to revise how ADIT is calculated in the PSCo and SPS formula rates generally conforms to the ADIT-related formula rate revisions accepted by the Commission in *Virginia Electric,* Xcel Energy has acknowledged in its March 21 Answer that certain steps are omitted from PSCo's and SPS's formula rate templates that are necessary to demonstrate how PSCo and SPS will implement the IRS's regulations concerning treatment of ADIT, consistent with *Virginia Electric*.[66] Therefore, we will direct PSCo to submit these additional calculations in a compliance filing to be submitted within 30 days of the date of this order.

38. We further find no merit to Golden Spread's assertions related to whether specific account balances will be subject to the proration requirement. Golden Spread admits that this issue is not readily apparent in proposed changes to the template included in PSCo's filing, and relies on evidence from the "SPS Projection."[67] Here, PSCo proposes to implement revisions to conform its formula rate to a methodology prescribed by the IRS in its regulations, and the issue of how application of these formula revisions applies to SPS's

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[64] PSCo, Docket No. ER16-236-000, Transmittal at 3 (citing I.R.S. Priv. Ltr. Rul. 143241-14 at 8).

[65] *Virginia Electric*, 154 FERC ¶ 61,126.

[66] *Id.*

[67] *See* Golden Spread Limited Protest at 8-9.

projected charges for 2016 is outside the scope of the issues raised in this proceeding. For such objections related to the inputs into the formula rate, Golden Spread may challenge the actual inputs when the annual update of the formula rate is filed. However, in response to Golden Spread's request that SPS be directed to clarify its Worksheet D regarding lack of clarity regarding which account balances will be subject to proration, we note that PSCo voluntarily submitted in its Deficiency Response revisions to SPS's Worksheet D clarifying in a new footnote that "proration is applied to plant related items impacted by Internal Revenue Service rules governing tax normalization."[68] Golden Spread has not protested this revision, and we find this clarification to be a reasonable method to comply with the relevant IRS regulations.

<u>The Commission orders</u>:

(A) PSCo's filings are hereby accepted, subject to condition, effective January 1, 2016, as requested, as discussed in the body of this order.

(B) PSCo is hereby directed to submit a compliance filing within 30 days of the date of this order, as discussed in the body of this order.

By the Commission. Commissioner Clark is not participating.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

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[68] Deficiency Response at 2.

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-15-826		
Response To:	MN Department of Commerce	Information Request No.	1168
Requestor:	Nancy Campbell, Dale Lusti, Angela Byrne		
Date Received:	May 5, 2016		

Question:

Reference: No Reference

Subject: Federal Income Taxes

When is the last time Xcel Energy paid any federal income taxes? Please provide information to support your response.

Response:

Xcel Energy Inc. pays federal income tax on a consolidated basis for all its affiliates, which includes the utility operating companies (such as NSPM). Xcel Energy Inc. last paid material federal income taxes in 2008.[1] Please refer to Attachment A to this response, which is page one of the 2008 consolidated federal income tax return (Form 1120) filed by Xcel Energy Inc. and Affiliates. Line 31 of this form supports the consolidated $22.3 million liability for 2008.

Consistent with prior treatment of the Company's income tax returns, Attachment A to this response has been marked Non-Public in its entirety, as it contains information the Company considers to be trade secret data as defined by Minn. Stat. §13.37(1)(b). It derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons who

[1] Since 2008, Xcel Energy Inc. has paid small amounts in federal income tax, totaling less than $1 million for the period 2009-2015.

could obtain economic value and/or a competitive advantage from its disclosure or use. Thus, Xcel Energy maintains this information as a trade secret.

Attachment A provided with the non-public version of this response has been marked "Trade Secret" in its entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material**: Attachment A includes page one of the 2008 consolidated federal income tax return (Form 1120) filed by Xcel Energy Inc. and Affiliates.
2. **Authors**: The form was prepared by Xcel Energy's corporate tax department.
3. **Importance**: The form includes corporate financial information that Xcel Energy maintains as trade secret.
4. **Date the Information was Prepared**: The information was prepared in 2009 for filing with the Internal Revenue Service.

Preparer:	Naomi Koch
Title:	Manager, Tax Reporting
Department:	Tax Services
Telephone:	612-330-7523
Date:	May 18, 2016

PUBLIC DOCUMENT
TRADE SECRET INFORMATION AND NON-PUBLIC DATA EXCISED

Attachment A provided with the non-public version of this response has been marked "Trade Secret" in its entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material**: Attachment A includes page one of the 2008 consolidated federal income tax return (Form 1120) filed by Xcel Energy Inc. and Affiliates.

2. **Authors**: The form was prepared by Xcel Energy's corporate tax department.

3. **Importance**: The form includes corporate financial information that Xcel Energy maintains as trade secret.

4. **Date the Information was Prepared**: The information was prepared in 2009 for filing with the Internal Revenue Service.

IRS rules that formula rate projections must include prorated accumulated deferred income taxes to avoid normalization violation

August 2015

In brief

In a series of private letter rulings (PLRs) for taxpayers in the power and utility industry, the IRS concluded that when a taxpayer's formula rate filing is based on a projected test period, the taxpayer must apply the so-called 'proration formula' to its accumulated deferred income taxes (ADIT).

The IRS determined in the PLRs that as long as the utility applies the proration formula in future filings, no normalization 'violation' would result.

In detail

Background

When a projected test period is used to determine a utility's revenue requirement, the Internal Revenue Code (IRC) requires ADIT to be deducted from the rate base (or included as zero-cost capital in the capital structure) and calculated using a 'proration formula.' The proration formula applies to ADIT related to accelerated depreciation.

The proration formula, described in Reg. sec. 1.167(l)-1(h)(6)(ii), is intended to account for the time for which the taxpayer has received the ADIT interest-free loan from the IRS. The proration formula limits the amount of ADIT that may be excluded from the rate base by considering the length of time the deferred tax accruals are actually recorded in ADIT.

For example, assume:

- A projected test year beginning January 1, 2017, and ending December 31, 2017
- Rate base determined using a 13-month average test year for plant in service and accumulated depreciation
- Proration credited to the deferred tax account mid-month each month

Under the proration formula, the taxpayer computes the related ADIT by beginning with the December 31, 2016, balance and adding the increase to ADIT for January 2017 multiplied by 345/365; the increase to ADIT for February 2017 by 315/365; the increase to ADIT for March 2017 by 284/365; and so forth until adding the increase to ADIT for December 2017, multiplied by 15/365. The assumption is that the utility will have the use of the ADIT interest-free loan from January 2017 for almost the entire year while the December 2017 ADIT interest-free loan will be available only for a short time.

FERC formula rates

One jurisdiction that uses formula rates is the FERC. The FERC permits revenue requirements for transmission entities to be computed using a formula rate template. The components of the revenue requirements are the typical rate base, rate of return, and operating expense factors, relying heavily on the FERC Uniform System of Accounts. Revenue requirement filings are submitted on September 1, with new rates effective January 1 of the following year. The test period can be projected; and if it is, a true-up calculation is required once the actual FERC Form 1 is filed. Any 'over' or 'under' between projected revenue requirements and actual revenues and costs using Form 1 data is billed or refunded to customers.

Recent PLRs

The IRS addressed this issue in a recent series of PLRs. We assume "Commission" as used in the PLRs refers to FERC, but the redacted versions of the PLRs prevent us from being certain. Several taxpayers requested guidance regarding whether the proration formula is required for Commission formula rate filings when a projected test period is used. The question is whether the fact that the projection is trued up to actual means that, in substance, a historical test period is being used — that is, whether the true-up mechanism 'converts' the projected period to actual.

In these rulings — identical PLRs 201531010, 201531011, and 201531012 — the IRS noted that the consistency rules, which address consistency between the components of the rate base, provide that if an average test year is used to determine plant in service and accumulated depreciation, an average test period must be used for ADIT. The proration formula determines the end-of-period balance for ADIT. The IRS noted that 'averaging' and 'pro rata' are not the same.

The PLRs define the terms 'historical period' and 'projected period' as they apply to this issue. The projected period is the portion of the period when new rates are in effect. Thus, if the projected test period is January 1, 2017, through December 31, 2017, and new rates are to be effective beginning January 1, 2017, then the entire test period is a projection. If, on the other hand, the projected test period is January 1, 2017, through December 31, 2017 and new rates will become effective April 1, 2017, then the proration formula would require the ADIT balance to be calculated beginning with the March 31, 2017, balance (end of the historical period) and applying proration to the period April 1, 2017, through December 31, 2017, (the projected period).

In the PLRs, the IRS concluded that when a formula rate filing is based on a projected test period, the proration formula is required. The PLR states:

> *"Here, Taxpayer has used a template approved by Commission to calculate formula-based rates. Commission has, at all times, required that utilities under its jurisdiction use normalization methods of accounting. Taxpayer also intended at all times to comply with the normalization rules. However, Taxpayer concluded that the use of the true-up would allow the entirety of the rate calculation to be considered a purely historical period and thus not require the application of the proration formula described in § 1.167(l)-1(h)(6)(ii). As concluded above, this conclusion is not in accord with the normalization rules. However because both Commission and Taxpayer at all times sought to comply, because Taxpayer merely populated a Commission-approved formula template rather than Commission carefully considering the calculation and ordering its use by Taxpayer, and because Taxpayer will take the corrective actions described above, it is not currently appropriate to apply the sanction of denial of accelerated depreciation to Taxpayer."*

The lRS determined that as long as the utility applied the proration formula in future filings, it would not declare a normalization 'violation.' The basis for this determination was that neither party had intentionally violated the normalization rules, which pertain to projected test periods as long as future filings follow those rules.

The takeaway

Utilities with formula rates and projected test periods should revise their filings to comply with the IRS guidance. This would include FERC filers.

Since a projected filing will be based on a pro-rata calculation, while the true-up calculation will not, the result will be a true-up 'difference' for this issue.

Because many utilities may seek a separate filing to adjust their FERC formula rate template to make it clear that the ADIT amount needs to be determined using proration, they should consider adjusting the income tax computation in the template to take into account certain adjustments to that computation for the effects of flow-through, non-deductible depreciation of capitalized AFUDC-Equity, and also for income tax rate change effects. Many FERC formula templates consider only the amortization of investment tax credits when determining income tax expense in calculating revenue requirements. They do not consider the impact of these other items in the computation.

Let's talk

For a deeper discussion of how this may affect your business, please contact:

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☒ **Public Document**

Xcel Energy			
Docket No.:	E002/GR-15-826		
Response To:	MN Department of Commerce	Information Request No.	1139
Requestor:	Nancy Campbell, Dale Lusti, Angela Byrne		
Date Received:	April 22, 2016		

<u>Question:</u>

Reference: Direct Testimony of Lisa Perkett p 53-56, Schedule 11

Subject: Prorated Accumulated Deferred Taxes

a) Please provide on a spreadsheet the calculations and resulting adjustments for both the 3-year and 5-year rate plans, which would replace the pro-rated ADIT balances (current year difference) with the actual non-prorated balances once the ADIT balances become actual in the following year. Please assume that the true-up in the following year is done the same way Xcel calculated the ADIT balances in past rate cases and riders by using beginning of year and end of year average ADIT balances. Please include amounts on a total company and Minnesota Jurisdictional basis and support the allocator used.

b) Please reconcile your response for (a) with calculations shown on Schedule 11, when calculating the adjustments.

<u>Response:</u>

a) As indicated in the Company's supplemental response to Information Request No. DOC-157, based on recent Private Letter Rulings (PLRs) and more importantly Xcel Energy's recent FERC decision to order the use of the specific pro-rate logic consistent with recent PLRs in the FERC regulated formula rate process for two of our operating companies (Public Service Company of Colorado and Southwestern Public Service Company), which includes a true-up provision to actual results, the Company believes this approach is required to meet the normalization requirements of the IRS. We understand this question to request the Company to calculate the true-up without the proration that we believe is required by the IRS. As such we also believe that this would put the Company in a normalization violation for the Minnesota and all other jurisdictions. By way of perspective, the average Acculumated Deferred Income Tax (ADIT) offset to rate base is approximately $2.0 billion in the 2016 Test Year, increasing to $2.3 billion in the 2018 Plan Year. This rate base offset reduces overall annual revenue requirements, resulting in a benefit to customers of approximately $217 million in 2016 and increasing to $252 million in 2018. Violating normalization puts this rate base benefit for customers at risk. The FERC decision, with respect to this issue was included in DOC-157 as supplemented, is included as Attachment A to this response.

Attachment B to this response includes the calculated ADIT Prorated values and associated revenue requirement impacts included in the Company's 3-Year proposal. The 2016 amount was provided in the Direct Testimony of Ms. Anne E. Heuer's Schedule 23. The revenue requirement impact of these adjustments calculated at the last authorized ROE for the three years 2016 to 2018 are as follows for the original filing and does not reflect any changes due to the December 2015 federal tax law:

Year	Original Filed Amount
2016	6,334,566
2017	1,852,827
2018	1,771,531

Given that these adjustments are determined annually and without impact on the next year's determination, the numbers in the table above represent the maximum value of the reduction to revenue requirements that would occur when prorating ADIT balances for the true up.

With respect to allocations to the MN Electric Retail Jurisdiction, the ADIT Prorate calculations are based on the total annual deferred income tax expense at the MN Electric Retail Jurisdictional level including the expense calculated as part of the NOL determination which is based on the MN Retail taxable income. The basic deferred tax expense as provided at the Total Company level is first assigned or allocated to the electric utility operations and then assigned or allocated to the MN retail jurisdiction. The assignment or allocation of deferred tax expense follows the same process as all of the other capital related components of the asset such as the related plant balance, depreciation reserve balance, and book depreciation expense. This process is described in Section VI of Ms. Heuer's Direct Testimony. Utility and Jurisdictional Allocations and further supported in the Direct Testimony of Company witness Mr. Adam R. Dietenberger.

In PLR 201541010, the IRS reasserts that in case of future test periods, the ADIT proration methodology described in Reg. Sec. 1.167(l)-1(h)(6) has to be used. The IRS also makes it clear that the true-up process cannot be used to unwind the proration calculation of ADIT. The IRS's view is that forward-looking formula rates with true-up procedures employ a future test period subject to normalization requirements, and such formula rates must use the proration formula in estimating ADIT amounts, including carrying forward the amounts of ADIT calculated using the proration formula into the true-up. The IRS in PLR 201541010 states that, "[i]n calculating the true-up, proration applies to the original projection amount." The originally projected amount is thus carried forward into the true-up, and therefore is not "unwound" by reversing the proration calculation. PLR 201541010 is included as Attachment C to this response.

b) Schedule 11 to Company witness Ms. Lisa H. Perkett's Direct Testimony shows the prorate adjustment on annual deferred taxes that are at total Company and before rate adjustments. The bridge schedule included in Volume 4B Backup Workpapers, VIII. Adjustments, A38 ADIT Pro-rate, page A38-5 shows the link between Schedule 11 and Ms. Heuer's Schedule 23.

As set out in the Company's response to Information Request No. XLI-35, updated information to reflect the impacts of the 2015 PATH Act will be supplemented.

Witness:	Lisa H. Perkett
Preparer:	Lisa H. Perkett / Jeffrey C. Robinson
Title:	Principal Financial Consultant / Specialized Business Consultant
Department:	Capital Asset Accounting / Revenue Requirements - North
Telephone:	612-330-6950 / 612-330-5912
Date:	May 6, 2016

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc.	))	Docket No. ER16-197-000

MOTION TO LODGE ORDER ON REVISED ADIT TREATMENT AND MOTION FOR RECONSIDERATION OF AMEREN SERVICES COMPANY AND XCEL ENERGY SERVICES INC.

Pursuant to Rules 212 and 716 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"),[1] Ameren Services Company, on behalf of Ameren Illinois Company d/b/a Ameren Illinois ("Ameren Illinois") and Ameren Transmission Company of Illinois ("ATXI") (collectively, "Ameren"), and Xcel Energy Services Inc. ("XES"), on behalf of Northern States Power Company, a Minnesota corporation and Northern States Power Company, a Wisconsin corporation ("NSP Companies"),[2] respectfully move to lodge in Docket No. ER16-197-000 the attached *Order on Revised ADIT Treatment*, issued by the Commission on February 23, 2016 in Docket No. ER14-1831-001.[3] The *Order on Revised ADIT Treatment* is directly relevant to the issues in Docket No. ER16-197 because it concerns the application of the proration methodology described in Section 1.167(l)-1(h)(6)(ii) of the Treasury regulations.[4] Specifically, in the *Order on Revised ADIT Treatment*, the Commission

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1 18 C.F.R. §§ 385.212 & 385.716.

2 Ameren and XES are together referred to as "Indicated Transmission Owners."

3 *PJM Interconnection, L.L.C.*, 154 FERC ¶ 61,126 (2016) ("*Order on Revised ADIT Treatment*"). The *Order on Revised ADIT Treatment* is attached as Exhibit No. 1.

4 Treas. Reg. § 1.167(l)-1(h)(6)(ii).

accepted the proposal of Virginia Electric and Power Company, doing business as Dominion Virginia Power ("Dominion") to continue to apply the proration methodology to the originally projected Accumulated Deferred Income Tax ("ADIT") balances in performing the annual true-up calculations. In the Commission's December 30, 2015 order in the captioned proceeding, the Commission rejected Ameren's and the NSP Companies' similar proposals to continue to apply the proration methodology to the originally projected ADIT balances in performing the annual formula rate true-up calculations.[5] Indicated Transmission Owners therefore also move for reconsideration of the December 2015 Order, pursuant to Rule 212 of the Commission's Rules of Practice and Procedure.

I. BACKGROUND

On October 30, 2015, the Midcontinent Independent System Operator, Inc. ("MISO") and Certain MISO Transmission Owners[6] (collectively with MISO, "Filing Parties") submitted a filing[7] pursuant to section 205 of the Federal Power Act ("FPA") proposing certain revisions to the formula rate included in Attachment O of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff") for

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5 *Midcontinent Indep. Sys. Operator, Inc.*, 153 FERC ¶ 61,371 (2015) ("December 2015 Order").

6 The Certain MISO Transmission Owners consist of: Ameren Services Company, as agent for Ameren Illinois and ATXI; Minnesota Power (and its subsidiary Superior Water, L&P) (collectively, "Minnesota Power"); Montana-Dakota Utilities Co. ("MDU"); Northern Indiana Public Service Company ("NIPSCo"); NSP Companies; Otter Tail Power Company ("Otter Tail"); and Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana) ("Vectren").

7 Revisions to Attachment O Formula Rates of the Midcontinent Independent System Operator, Inc. and the Certain MISO Transmission Owners, Docket No. ER16-197-000 (Oct. 30, 2015) ("October 2015 Filing").

Certain MISO Transmission Owners.[8] Specifically, Filing Parties proposed to revise Note F of their company-specific Attachment Os in the Tariff to clarify that they would calculate the ADIT balances used in the calculation of the projected test year revenue requirement using the proration methodology set forth in Section 1.167(l)-1(h)(6)(ii) of the United States Treasury regulations.[9] Three of Certain MISO Transmission Owners—Ameren Illinois, ATXI, and NSP Companies—further proposed to revise Note F of their company-specific Attachment Os to state that the calculations of ADIT balances in the annual true-up calculation would be performed so as to preserve the effect of the application of the proration methodology used in the projected test year calculation. The revised Note F required that Certain MISO Transmission Owners post the work papers supporting the ADIT calculations with each Annual True-Up and/or projected revenue requirement and include the work papers in their annual Informational Filing submitted to the Commission. Filing Parties requested an effective date of January 1, 2016, for the modifications proposed.

In the December 2015 Order, the Commission accepted the October 2015 Filing, subject to conditions. The Commission accepted the proposed revisions to Note F to apply the IRS regulations to the annual projected ADIT amounts for Minnesota Power, MDU, NIPSCo, Otter Tail, and Vectren.[10] The Commission found, however, that the true-up provisions proposed by Ameren Illinois, ATXI, and NSP Companies had not

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8 The company-specific Attachment Os were filed for Ameren Illinois, ATXI, Minnesota Power, MDU, NIPSCo, NSP Companies, Otter Tail, and Vectren.

9 *See* Treas. Reg. § 1.167(l)-1(h)(6)(ii).

10 December 2015 Order at P 37.

been justified as just and reasonable.[11] Accordingly, the Commission directed Filing Parties to "revise the proposed Tariff changes to remove reference to the use of an IRS calculation for the annual true-up, and to provide that annual true-up calculations will continue to use the average of the beginning-of-year and end-of-year balances for all ADIT accounts."[12] In addition, the Commission directed Filing Parties, in a compliance filing, to include the work papers supporting the ADIT calculations with the company-specific Attachment O of each of Certain MISO Transmission Owners.[13]

On January 29, 2016, Indicated Transmission Owners submitted a request for clarification or, in the alternative, rehearing of the December 2015 Order.[14] Indicated Transmission Owners requested the Commission clarify that, should the Internal Revenue Service ("IRS") rule that the proration methodology described in Section 1.167(l)-1(h)(6)(ii) of the Treasury regulations must continue to be applied to the originally projected ADIT balances in performing the annual true-up calculations, Indicated Transmission Owners are not estopped by the December 2015 Order from making a future filing with the Commission consistent with the IRS's direction.[15] Furthermore, should the Commission deny their request for clarification, Indicated Transmission Owners requested rehearing of the December 2015 Order's finding that the Treasury

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[11] *Id.* at P 38.

[12] *Id.*

[13] *Id.* at P 39.

[14] Request for Clarification or, in the Alternative, Rehearing of Ameren Services Company and Xcel Energy Services Inc., Docket No. ER16-197-002. ("Request for Clarification of Rehearing").

[15] Request for Clarification or Rehearing at 5-6.

regulations do not require applying the proration calculation to any portion of the annual true-up.[16] The Request for Clarification or Rehearing is currently pending before the Commission.

Also on January 29, 2016, Filing Parties submitted a compliance filing including work papers supporting the ADIT calculations for each company-specific Attachment O of each of the Certain MISO Transmission Owners.[17] Filing Parties also modified the Attachment O templates of Ameren Illinois, ATXI, and NSP Companies as required.[18]

II. MOTION TO LODGE

The Commission grants motions to lodge where parties have presented good cause for granting the motion.[19] Indicated Transmission Owners' motion to lodge is appropriate here because the December 2015 Order in contrary to the *Order on Revised ADIT Treatment*.

In the *Order on Revised ADIT Treatment*, the Commission accepted Dominion's proposal to retain the IRS's proration methodology for the originally projected ADIT amount when calculating the true-up.[20] The Commission summarized Dominion's proposal in Docket No. ER14-1831, stating that "[r]egarding the true-up adjustment, Dominion proposes to retain the IRS's proration methodology for the originally projected

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16 *Id.* at 6-9.

17 Compliance Filing Revising Attachment O Formula Rates of Midcontinent Independent System Operator, Inc. and the Certain MISO Transmission Owners, Docket No. ER16-197-001 (Jan. 29, 2016) ("Compliance Filing").

18 Compliance Filing at 4.

19 18 C.F.R. § 385.716.

20 *Order on Revised ADIT Treatment* at 21.

[ADIT], but not to apply the proration to any actual [ADIT] activity in excess of that amount."[21] The Commission found Dominion's proposal to be consistent with the Private Letter Ruling ("PLR") Dominion filed in Docket No. ER14-1831.[22] Specifically, the Commission quoted the PLR's finding that "in calculating the true-up, proration applies to the original projection amount but the actual amount added to the [ADIT] over the test year is not modified by application of the proration formula."[23]

In the December 2015 Order, the Commission rejected Ameren's and the NSP Companies' proposal to apply the proration methodology to the originally projected ADIT amount in calculating the true-up. As Indicated Transmission Owners explained in their Request for Clarification or Rehearing, it is necessary to preserve the proration in the original projected ADIT balances by again applying the proration formula when adjusting the actual ADIT balances and calculating the true-up.[24] The Commission recognized this logic in the *Order on Revised ADIT Treatment*;[25] thus, the Commission should grant this motion to lodge that order in the record of this proceeding.

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21 *Id.* at P 8.

22 *Id.* at P 21. *See* Filing Supplementing the Record with an Internal Revenue Service Private Letter Ruling and Requesting Additional Time for Compliance of Virginia Electric and Power Company, Docket No. ER14-1831-000, Attachment (Private Letter Ruling) (Aug. 14, 2015).

23 *Order on Revised ADIT Treatment* at P 21 (quoting I.R.S. Priv. Ltr. Rul. 143241-14, at 8 (July 6, 2015)).

24 Request for Clarification or Rehearing at 8.

25 *Order on Revised ADIT Treatment* at P 8.

III. MOTION FOR RECONSIDERATION

The Commission also should grant Indicated Transmission Owners' motion for reconsideration of the December 2015 Order. As demonstrated above, Ameren's proposal in the October 2015 Filing to revise Note F of the Ameren Illinois and ATXI company-specific Attachment O to specify that the proration methodology would be applied in performing the true-up calculation mirrors the proposal which the Commission accepted for Dominion in Docket No. ER14-1831-001.[26] Similarly, the proposed changes to Note F of Attachment O-NSP also specify that the proration methodology would be applied in performing the true-up calculation.

Furthermore, with only a few minor differences, the illustrative ADIT work papers that Ameren included in its December 7, 2015 response to the protest of Southwestern Electric Cooperative, Inc. ("Southwestern")[27] are substantially similar to

[26] *See* October 2015 Filing, Exhibit II, Attachment O-AIC, Note F ("The calculations of ADIT for Account 282, as well as the portion of Account 190 related to federal net operating losses, in the projected net revenue requirement *and the Annual True-Up calculation* will be performed in accordance with IRS regulation Section 1.167(l)-1(h)(6).") (emphasis added); *id.*, Exhibit II, Attachment O-ATXI, Note F (same).

[27] Motion for Leave to Answer and Answer of Ameren Services Company, Docket No. ER16-197-000 (Dec. 7, 2015) ("Ameren Answer"). Exhibit No. 1 to the Ameren Answer is an illustrative work paper showing the actual proration calculation for the projected 2016 amounts for Account No. 282. Exhibit No. 2 to the Ameren Answer is a "true-up proration example" showing how Ameren expects the true-up proration calculation to work, once Ameren has 2016 actual amounts for the calculation. Ameren is including revised versions of these ADIT work papers as Exhibit No. 2 to this filing. The format of the ADIT revised work paper is consistent with the work paper filed in the Compliance Filing, which is now part of the Tariff. Ameren also notes that the true-up proration examples reflect a hypothetical population of the true-up template.

the ADIT work papers that Dominion included in its October 30, 2015 filing.[28] Therefore, to provide consistency and clarity regarding the application of the proration methodology when calculating the true-up for forward-looking formula rates, the Commission should grant Ameren's request for reconsideration of the December 2015 Order.

The calculations provided in Dominion's ADIT work papers are generally, though not entirely, consistent, as discussed below, with the calculations set forth in the illustrative work papers included in the Ameren Answer. Ameren, like Dominion, interprets the Treasury regulations to require that, in the event the projected ADIT amount is equal to the actual ADIT amount, the proration calculation must be applied to the original projected ADIT amount. Ameren, like Dominion, also interprets the Treasury regulations to require that, to the extent the actual ADIT amount exceeds the projected ADIT amount, the proration formula does not apply to the incremental difference between the actual ADIT amount and the projected ADIT amount. Similarly, to the extent the actual ADIT amount is less than the projected ADIT value, but still represents an increase in ADIT, Ameren agrees with Dominion that the projected ADIT amount is to be decreased by the difference between the projected and actual ADIT amounts.

The ADIT work papers included in the Ameren Answer differ from Dominion's ADIT work papers in a few minor respects. First, according to Dominion's work papers,

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28 Compliance Filing Revising ADIT Treatment in OATT Formula Transmission Rate of Virginia Electric and Power Company, Docket No. ER14-1831-001, Exhibit No. DVP-8 (Sample populated Attachment 1B), Exhibit No. DVP-9 (Sample populated Attachment 1C) (Oct. 30, 2015). Ameren has included Dominion's ADIT work papers as Exhibit No. 3.

when actual ADIT activity is less than projected ADIT activity, and represents an overall decrease in ADIT, Dominion will not use the originally projected ADIT amount. Dominion will instead use the actual decrease to the ADIT value. In the ADIT work papers included with the Ameren Answer, there was a formula problem in this column, causing this piece of the calculation to not agree with Dominion's methodology. However, in the revised ADIT work papers included herein as Exhibit No. 2, Ameren has corrected the formula in column Q (Partially prorated actual balance) to be consistent with the calculation in the Dominion work papers.

Second, in its ADIT work papers for Account No. 282, Dominion breaks the calculations down into transmission service plant in service, general plant, and computer software. Ameren's proposed ADIT work papers do not break Account No. 282 down into these components as Ameren does not track deferred taxes at this level in its ledger and does not forecast projected deferred taxes at this level. Finally, it appears that Dominion will be prorating only the federal ADIT. Conversely, Ameren's calculation is a proration of the entire portion of Account No. 282 attributable to transmission, as well as any deferred tax asset in Account No. 190 related to federal net operating losses.

The December 2015 Order is inconsistent with the *Order on Revised ADIT Treatment* to the extent it prohibits Ameren from applying the IRS's proration methodology in calculating the true-up. Moreover, the calculations contained in Ameren's revised ADIT work papers mirror those of Dominion, which the Commission accepted as just and reasonable.

As such, the Commission should grant Indicated Transmission Owners' motion for reconsideration. Ameren commits to making a compliance filing with revised Attachment O-AIC and Attachment O-ATXI templates, and including the revised ADIT work papers upon the Commission's direction. Similarly, XES commits to making a compliance filing with a revised Attachment O-NSP template, and including revised ADIT work papers similar to the Dominion work papers accepted in the *Order on Revised ADIT Treatment* upon the Commission's direction. The revised templates and work papers would then be used in calculating the 2016 true-ups of the Attachment O-AIC, Attachment O-ATXI, and Attachment O-NSP templates performed in 2017.

IV. CONCLUSION

For the reasons set forth above, Indicated Transmission Owners respectfully request that the Commission grant its motion to lodge the *Order on Revised ADIT Treatment* in Docket No. ER16-197-000 and their motion for reconsideration of the December 2015 Order.

Respectfully submitted,

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March 11, 2016

Exhibit No. 1

154 FERC ¶ 61,126
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, Tony Clark,
and Colette D. Honorable.

PJM Interconnection, L.L.C.
Virginia Electric and Power Company

Docket No. ER14-1831-001

ORDER ON REVISED ADIT TREATMENT

(Issued February 23, 2016)

1. On October 30, 2015, Virginia Electric and Power Company, doing business as Dominion Virginia Power (Dominion), submitted a compliance filing in the above referenced proceeding, following its receipt of an Internal Revenue Service (IRS) Private Letter Ruling (PLR).[1] As discussed below, we accept these company-specific revisions to Attachment H-16 of PJM Interconnection, L.L.C.'s (PJM) Open Access Transmission Tariff (Tariff), with an effective date of May 1, 2014, as requested.[2]

I. Background

2. Under Commission ratemaking policies, income taxes included in rates are determined based on the return on net rate base calculated using straight-line depreciation. However, in calculating the actual amount of taxes due to the IRS, companies generally are able to take advantage of accelerated depreciation. Accelerated depreciation will generally lower taxes payable during the early years of an asset's life followed by corresponding increases in taxes payable during the later years of an asset's life. This means that a company's income taxes payable in a period will differ from its income tax expense in the same period for ratemaking purposes. The difference between the income taxes based on straight-line-depreciation and the actual taxes paid by the company are reflected in an account called Accumulated Deferred Income Taxes (ADIT)

[1] I.R.S. Priv. Ltr. Rul. 143241-14 (July 6, 2015) (PLR).

[2] PJM Interconnection, L.L.C., Intra-PJM Tariffs, OATT ATT H-16A, OATT Attachment H-16A - Virginia Electric, 6.0.0.

or Accumulated Deferred Federal Income Taxes (ADFIT). Because the customers are, in effect, pre-paying taxes and providing the company with cost-free capital, the Commission subtracts the ADFIT from the company's rate base thereby reducing customer charges. This method of passing the benefits from accelerated depreciation on to ratepayers throughout the asset's life is referred to as tax normalization.

3. The depreciation normalization rules of the Internal Revenue Code (Normalization Rules) mandate the use of a very specific proration procedure in measuring the amount of future test period ADFIT that can reduce rate base. The IRS requires, for a utility that solely utilizes a future period (projected test year) to determine depreciation, that "the amount of the reserve [for deferred taxes] for the period is the amount of the reserve at the beginning of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during such period."[3] The pro rata amount of any increase or decrease during the future portion of the period is determined by multiplying the increase or decrease by a fraction, the numerator of which is the number of days remaining in the period at the time the increase is to accrue, and the denominator of which is the total number of days in the future portion of the period.[4] The purpose of the Proration Requirement is to prevent the immediate flow-through of the benefits of accelerated depreciation to ratepayers, allowing funds provided by accelerated depreciation to be used for investments.

4. The IRS requires utilities to follow its regulations in order to take advantage of accelerated depreciation. Dominion and other electric utilities have requested revenue rulings from the IRS regarding the calculation of ADFIT for formula rates which include a projection of expected investments for the coming year. These formula rates also include a true-up mechanism through which the utility calculates adjustments to its formula, for example, for the differences from investments that did not occur when projected.

5. On April 30, 2014, Dominion filed in Docket No. ER14-1831-000, pursuant to section 205 of the Federal Power Act,[5] to change the methodology it uses to calculate the ADFIT component of its rate base to bring it into compliance with the Normalization Rules and thereby continue the availability of accelerated tax depreciation to the benefit of its customers. Specifically, Dominion stated that the IRS's proration formula must be applied to its ADFIT balance (Proration Requirement). Additionally, Dominion asserted that once the proration formula is applied, the ADFIT balance used to reduce rate base

[3] Treas. Reg. § 1.167(1)-1(h)(6)(ii).

[4] *Id.*

[5] 16 U.S.C. § 824d (2012).

must be calculated using the same 13-month average that is used in calculating the net plant component of rate base (Consistency Requirement). In a June 2014 Order,[6] the Commission ruled that Dominion's particular tax question was "a case of first impression before this Commission … on the specific matters of tax law raised," and ruled "that it is necessary to obtain the IRS's interpretation of how its Normalization Rules apply in the context of Dominion's Formula Rates."[7] Accordingly, the June 2014 Order formally established a hearing, but held all proceedings at the Commission in abeyance until Dominion received guidance directly from the IRS. On July 6, 2015, the IRS released that guidance in the form of a PLR, which is its primary mode of ruling on fact-specific questions of interpreting the tax code.

6. On August 14, 2015, Dominion filed the PLR in this docket and announced that it had taken effect under IRS rules of procedure. Dominion had asked the IRS:

> to determine whether the Proration and Consistency Requirements of the Normalization Rules are required in the case of a rate recovery mechanism, whereby: (1) the cost of service test period includes projected periods, i.e., periods subsequent to the effective date of the rates, and (2) the differences between such projected costs and the utility's actual incurred costs are included as an adjustment to cost-of-service in the next resetting of the rates for the recovery mechanism.[8]

According to Dominion, the PLR announced seven conclusions, five of which conformed with Dominion's expectations as reflected in its original filing, and two of which differed from Dominion's expectations.[9] In particular, Dominion characterizes the IRS as ruling:

> while the Proration Requirement applies to all future test periods and the estimated projection components of the Formula Rate, the Proration Requirement is not applicable to the increase of actual ADIT activity above the original projections when computing the true-up portion of the Formula Rate. It also ruled that the Consistency Requirement

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[6] *PJM Interconnection, L.L.C.*, 147 FERC ¶ 61,254 (2014) (June 2014 Order).

[7] *Id.* P 18.

[8] Dominion August 14, 2015 Supplemental Filing at 2.

[9] *Id.* at 2.

> was not violated by using the two different averaging methodologies for plant components of rate base and related ADIT that has been historically used in Dominion's Formula Rate.

Dominion sought, and was granted, additional time to revise its tariff proposal to be in line with the IRS's determinations.

7. On October 30, 2015, Dominion submitted the instant compliance filing. Dominion addressed the calculation of ADFIT for use in both the projected test period and the true-up adjustment. Regarding the projected test period, Dominion states that its proposal on April 30, 2014, in which Dominion proposed to use proration in calculating ADFIT, is generally consistent with the PLR. However, Dominion asserts that it is unnecessary to use the same 13-month average that it uses to calculate net plant for ADFIT, and Dominion instead proposes to use an average based on the beginning-of-year and end-of -year prorated values. Dominion cites the PLR's finding that "[w]hile there are minor differences in the convention used to average all elements of rate base including depreciation expense on the one hand, and ADFIT on the other… it is sufficient that both are determined by averaging and both are determined over the same period of time."[10]

8. Regarding the true-up adjustment, Dominion proposes to retain the IRS's proration methodology for the originally projected ADFIT amount, but not to apply proration to any actual ADFIT activity in excess of that amount. In support of its proposed changes to the true-up calculation, Dominion refers to the PLR's finding that "In calculating the true-up, proration applies to the original projection amount but the actual amount added to the ADFIT over the test year is not modified by application of the proration formula."[11] Dominion contends that although this ruling "might at first appear counterintuitive, it preserves both the economic effect of the IRC-required proration and the definitions of 'future' and 'historical' test periods provided in the PLR."[12] Dominion advises that it has confirmed with the IRS that this was the intent of the PLR.[13]

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[10] PLR at 10, *cited in* Dominion October 30, 2015 filing at 6.

[11] PLR at 7, *cited in* Dominion October 30, 2015 filing at 7.

[12] Dominion October 30, 2015 filing at 7.

[13] *Id.*

II. Notice and Responsive Pleadings

9. Notice of Dominion's filing was published in the Federal Register, 80 Fed. Reg. 68,528 (2015), with interventions and protests due on or before November 20, 2015. Virginia Municipal Electric Association No. 1, Old Dominion Electric Cooperative, and the North Carolina Electric Membership Corporation intervened and jointly (collectively, Indicated Customers) filed a timely protest. On December 8, 2015, Dominion filed a motion for leave to answer and answer to the protest of Indicated Customers. On December 22, 2015, Indicated Customers filed an answer to Dominion's answer.

10. Indicated Customers allege that Dominion misinterprets certain aspects of the IRS's regulations and the PLR's guidance. First, Indicated Customers complain that after Dominion performs its proration calculation, it takes the extra step of averaging the beginning and ending balance.[14] Indicated Customers contend that this extra step is duplicative, because the proration process itself has the effect of averaging ADFIT balance over the December-to-December period. Second, Protestors contend that Dominion has incorrectly interpreted the IRS's response in the PLR to mean that only the difference between the forecast of the ADFIT during the year and the amount of ADFIT that was actually booked is exempt from the proration requirement.[15] Indicated Customers contend that it is "the actual amount added to the ADFIT over the test year" – that is, all of the ADFIT accrued during the test year – that is exempt from proration, not merely the difference between the projection and the actual amount.[16] Finally, Indicated Customers object to Dominion's proposed effective date. Indicated Customers assert that there is no need to restate the 2014 and 2015 projected amounts for ADFIT to reflect proration, since the projected rates have already been paid by transmission customers.

11. In answering the Indicated Customers' Protest, Dominion argues that the IRS's regulations require proration of the test period data and averaging of the prorated data over that period.[17] According to Dominion, under the Consistency Requirement, it must apply the same convention (e.g., an averaging convention) to the prorated ADFIT amounts that it applies to the other elements of rate base. However, Dominion notes that the Consistency Requirement accommodates the use of variations in averaging conventions. In other words, the averaging methodology used for ADIT and other components of rate base can be based upon different conventions provided all related

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[14] Indicated Customers Protest at 4.

[15] *Id.* at 5.

[16] *Id.*

[17] Dominion Answer at 5-7.

components (plant, accumulated depreciation, ADIT) are averaged.[18] Thus, Dominion explains that, since it averages balances in calculating other elements of its rate base, it must apply an averaging convention to the prorated ADFIT balances as well.[19]

12. With respect to the true-up, Dominion argues that the PLR requires it to preserve the proration of the ADFIT that was used for projected rates. Dominion explains that the PLR describes the true-up component as a reconciliation mechanism wherein actual amounts that are in excess of projections are collected from customers in a subsequent rate year.[20] Dominion quotes the PLR as stating, "the true up increases the ultimate accuracy of the rates but does not convert a future test period into a historical test period as those terms are used in the normalization regulations."[21] Dominion suggests that, under IRS regulations, a true-up is not the same as a historical test period. Dominion further notes that the PLR holds, "[i]n calculating the true-up, proration applies to the original projection amount but the actual amount added to the ADFIT over the test year is not modified by application of the proration formula."[22] Dominion explains that the true-up amount to be billed to customers represents only the difference between a revenue requirement determined in that recalculation and the revenue requirement determined in the original projected component of the formula rate. Dominion advises that recognition of this distinction is critical to understanding the PLR guidance provided by the IRS.

13. According to Dominion, the true-up adjustment included within the Annual Transmission Revenue Requirement (ATRR), as reflected in Dominion's formula rate templates, is limited to the ADFIT included in the projected component of the formula rate but not to the incremental changes in ADFIT (the "actual amount added") attributable to the differences between the projected amounts already included in the rate period and the total actual ADFIT balances. Dominion explains that it is only such differences in ADFIT activity, rather than the entirety of the ADFIT activity reflected in the recalculation, that would occur before the effective date of attendant rates or be considered *historical* as that term is used by the IRS in its interpretation of the proration

[18] *Id.*

[19] Dominion Answer at 7 (citing I.R.S. Priv. Ltr. Rul. 9202029 (October 15, 1991); I.R.S. Priv. Ltr. Rul. 9313008 (December 17, 1992); I.R.S. Priv. Ltr. Rul. 9224040 (March 16, 1992)).

[20] Dominion Answer at 9.

[21] PLR at 8, *cited in* Dominion Answer at 12.

[22] PLR at 8, *cited in* Dominion Answer at 8.

formula provisions of its regulations. On the other hand, projected ADFIT activity, to the extent realized, has already impacted the revenue requirement underlying customer rates that became effective prior to the projected periods. Accordingly, only the differences are not subject to the proration requirements, Dominion argues.

14. Regarding its requested effective date, Dominion states that its goal is to limit the period of non-compliance with the Normalization Rules. Dominion states that its proposal would apply the PLR-compliant true-up computation beginning with the May 1, 2014 effective date established by the Commission (subject to refund) in this proceeding. Dominion states that this does not involve applying the Normalization Rules to the projections for 2014 through 2016.

15. Dominion states that if the Commission's decision in this proceeding varies from Dominion's understanding of the PLR, Dominion may determine that a subsequent PLR request is required to provide confirmation that the resulting tariff conforms to the IRS's requirements.

16. In their December 22, 2015 answer, Indicated Customers reiterate the objections summarized above. Indicated Customers assert that Dominion's proposal will needlessly increase rates for customers.

III. Discussion

17. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure,[23] the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure prohibits an answer to a protest unless otherwise ordered by the decisional authority.[24] We will accept Dominion's December 8, 2015 answer and Indicated Customers' December 22, 2015 answer.

18. In this filing, Dominion seeks to have the Commission accept revisions to its formula rate to reflect the IRS's regulations for calculating deferred income taxes for purposes of determining Dominions Transmission Formula Rate. Dominion asserts that these revisions are necessary in order to preserve Dominion's ability to use accelerated depreciation for federal income tax purposes. We agree with Dominion that its proposal is a reasonable interpretation of the PLR.

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[23] 18 C.F.R. § 385.214 (2015).

[24] 18 C.F.R. § 385.213(a)(2) (2015).

19. In recent orders, the Commission has clarified that, when a section 205 filing is strictly limited to tax matters, the Commission will base its evaluation on whether "the proposed revisions are reasonable to comply with IRS regulations,"[25] and expressly rejected the "objection that Private Letter Rulings issued by the IRS cannot be a basis for [] proposed rate revisions."[26] The Indicated Customers, following this guidance, have limited its protest to arguing "that Dominion has misinterpreted certain aspects of the IRS's guidance."[27] Accordingly, Indicated Customers argue that, "Dominion has improperly calculated the net prorated amount for use in the projected formula rates,"[28] and "also misunderstood the guidance provided by the PLR regarding the true-up component of the formula rate;"[29] the Indicated Customers' requested revisions to Dominion's rates all flow from this argument.

20. Indicated Customers maintain that Dominion has added an unrequired separate step of averaging the beginning and ending ADFIT balances not required by the PLR. They maintain that prorationing is an average and that Dominion therefore should use the end of year pro rated ADFIT balance, as opposed to the simple average. We find, however, that Dominion's methodology is reasonable. Dominion's proposal determines the average rate base by taking the average net plant and subtracting an average of ADFIT values.[30] As the PLR states: "[w]hile there are minor differences in the convention used to average all elements of rate base including depreciation expense on the one hand, and ADFIT on the other… it is sufficient that both are determined by averaging and both are determined over the same period of time."[31] This interpretation

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[25] *Midcontinent Independent System Operator, Inc.*, 153 FERC ¶ 61,371, at P 36 (2015).

[26] *Id.* P 40.

[27] Indicated Customers' Protest at 3.

[28] *Id.* at 4.

[29] *Id.*

[30] Prorating an investment over time is not the equivalent of an average. Prorating weights the ADFIT from projected investments by the month in which they are incurred; an average uses the prorated monthly ADFIT values and determines the central or typical value from those data.

[31] PLR at 10, *cited in* Dominion October 30, 2015 filing at 6.

also is consistent with the interpretation of other utilities applying the IRS regulations regarding proration.[32]

21. Indicated Customers also object to Dominion's proposal to retain the IRS's proration methodology for the originally projected ADFIT amount. This treatment is consistent with the PLR, which states "in calculating the true-up, proration applies to the original projection amount but the actual amount added to the ADFIT over the test year is not modified by application of the proration formula."[33] Indicated Customers' contention that unweighted values should be used for the true-up would effectively undo the proration calculation of rates required by the IRS.

22. Finally, Indicated Customers object to Dominion's proposed May 1, 2014 effective date. However, the PLR states that "[a]ny rates that have been calculated using procedures inconsistent with this ruling ('nonconforming rates') which are or which have been in effect and which, under the applicable state or federal regulatory law, can be adjusted or corrected to conform to the requirements of this ruling, must be so adjusted or corrected."[34] Dominion's filing is consistent with the PLR.

The Commission orders:

Dominion's filing is accepted, effective May 1, 2014, as requested.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

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[32] *See, e.g., Midcontinent Independent Transmission Operator, Inc.*, 153 FERC ¶ 61,374 (2015).

[33] PLR at 7, *cited in* Dominion October 30, 2015 filing at 7.

[34] PLR at 10, *cited in* Dominion December 8, 2015 Answer at 15.

Exhibit No. 2

Northern States Power Company

Ameren Illinois

Accumulated Deferred Income Taxes

Year Ended December 31, 2016

Rate Year = *Projected 2016*

Line														
	Proration Used for Projected Revenue Requirement Calculation								**Proration Used for True-up Revenue Requirement Calculation**					
1	**Account 190**													
2	**Days in Period**					**Averaging with Proration - Projected**			**Averaging Preserving Projected Proration - True-up**					
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**L**	**M**	**N**
3	Month	Days in the Month	Number of Days Prorated	Total Days in Future Portion of Test Period	Proration Amount (C / D)	Projected Monthly Activity	Prorated Projected Monthly Activity (E x F)	Prorated Projected Balance (Cumulative Sum of G)	Actual Monthly Activity	Difference between projected and actual activity	Partially prorate actual activity above Monthly projection	Partially prorate actual activity below Monthly projection but increases ADIT	Partially prorate actual activity below Monthly projection and is a reduction to ADIT	Partially prorated actual balance
4														
5	December 31st balance Prorated Items							53,078,324						54,000,000
6	January	31	336	366	91.80%	1,746,377	1,603,231	54,681,555	1,500,000	(246,377)	-	226,182	-	55,377,049
7	February	29	307	366	83.88%	1,746,377	1,464,857	56,146,413	2,000,000	253,623	253,623	-	-	57,095,529
8	March	31	276	366	75.41%	1,746,377	1,316,940	57,463,353	(100,000)	(1,846,377)	-	-	(100,000)	56,995,529
9	April	30	246	366	67.21%	1,746,377	1,173,794	58,637,147	500,000	(1,246,377)	-	837,729	-	57,331,595
10	May	31	215	366	58.74%	1,746,377	1,025,877	59,663,024	-	(1,746,377)	-	1,025,877	-	57,331,595
11	June	30	185	366	50.55%	1,746,377	882,732	60,545,756	750,000	(996,377)	-	503,633	-	57,710,693
12	July	31	154	366	42.08%	1,746,377	734,814	61,280,570	350,000	(1,396,377)	-	587,547	-	57,857,961
13	August	31	123	366	33.61%	1,746,377	586,897	61,867,468	1,750,000	3,623	3,623	-	-	58,448,481
14	September	30	93	366	25.41%	1,746,377	443,752	62,311,219	(500,000)	(2,246,377)	-	-	(500,000)	57,948,481
15	October	31	62	366	16.94%	1,746,377	295,834	62,607,054	250,000	(1,496,377)	-	253,485	-	57,990,831
16	November	30	32	366	8.74%	1,746,377	152,689	62,759,742	50,000	(1,696,377)	-	148,317	-	57,995,203
17	December	31	1	366	0.27%	1,746,377	4,772	62,764,514	2,500	(1,743,877)	-	4,765	-	57,995,209
18	Total					20,956,525	9,686,190		6,552,500	(14,404,025)	257,246	3,587,535	(600,000)	
19	Beginning Balance				234.8.b			177,342,281						180,000,000
20	Less non Prorated Items				(Line 19 less line 21)			124,263,957			379,098			126,000,000
21	Beginning Balance of Prorated items				(Line 5, Col H)			53,078,324						54,000,000
22	Ending Balance				234.8.c			189,186,731						192,000,000
23	Less non Prorated Items				(Line 22 less line 24)			126,422,217						134,004,791
24	Ending Balance of Prorated items				(Line 17, Col H)			62,764,514						57,995,209
25	Average Balance				([Lines 21 + 24] /2)+([Lines 20 +23)/2])			183,264,506						186,000,000
26	Less FASB 106 & 109 Items				Attachment O, Footnote F			1,628,313						1,600,000
27	Amount for Attachment O				(Line 25 less line 26)			**181,636,193**						**184,400,000**

{W0083806.1 }

Northern States Power Company

Ameren Illinois
Accumulated Deferred Income Taxes
Year Ended December 31, 2016

Rate Year = *Projected 2016*

Proration Used for Projected Revenue Requirement Calculation | **Proration Used for True-up Revenue Requirement Calculation**

Line	A	B	C	D	E	F	G	H	I	J	K	L	M	N
28	**Account 282**								**This matches Exhibit #2 filed in ER16-197 Revised 3/3/16**					
29	**Days in Period**					**Averaging with Proration - Projected**			**Averaging Preserving Projected Proration - True-up**					
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**L**	**M**	**N**
30	Month	Days in the Month	Number of Days Prorated	Total Days in Future Portion of Test Period	Proration Amount (C / D)	Projected Monthly Activity	Prorated Projected Monthly Activity (E x F)	Prorated Projected Balance (Cumulative Sum of G)	Actual Monthly Activity	Difference between projected and actual activity	Partially prorate actual activity above Monthly projection	Partially prorate actual activity below Monthly projection but increases ADIT	Partially prorate actual activity below Monthly projection and is a reduction to ADIT	Partially prorated actual balance
31														
32	December 31st balance Prorated Items							(1,198,222,664)						(1,200,000,000)
33	January	31	336	366	91.80%	(5,595,391)	(5,136,752)	(1,203,359,416)	(5,795,391)	(200,000)	(200,000)	-	-	(1,205,336,752)
34	February	29	307	366	83.88%	(5,493,020)	(4,607,533)	(1,207,966,949)	(5,093,020)	400,000	-	(335,519)	-	(1,209,608,767)
35	March	31	276	366	75.41%	(5,704,282)	(4,301,589)	(1,212,268,539)	(5,704,282)	-	-	-	-	(1,213,910,356)
36	April	30	246	366	67.21%	(5,705,742)	(3,835,007)	(1,216,103,546)	(4,705,742)	1,000,000	-	(672,131)	-	(1,217,073,232)
37	May	31	215	366	58.74%	(5,826,898)	(3,422,905)	(1,219,526,450)	173,102	6,000,000	-	-	173,102	(1,216,900,130)
38	June	30	185	366	50.55%	(5,357,351)	(2,707,951)	(1,222,234,401)	(4,557,351)	800,000	-	(404,372)	-	(1,219,203,709)
39	July	31	154	366	42.08%	(5,357,697)	(2,254,332)	(1,224,488,733)	(5,257,697)	100,000	-	(42,077)	-	(1,221,415,964)
40	August	31	123	366	33.61%	(5,297,944)	(1,780,457)	(1,226,269,190)	(5,297,944)	-	-	-	-	(1,223,196,421)
41	September	30	93	366	25.41%	(5,607,420)	(1,424,836)	(1,227,694,026)	(5,307,420)	300,000	-	(76,230)	-	(1,224,545,028)
42	October	31	62	366	16.94%	(5,867,505)	(993,949)	(1,228,687,975)	(5,967,505)	(100,000)	(100,000)	-	-	(1,225,638,977)
43	November	30	32	366	8.74%	(5,735,411)	(501,457)	(1,229,189,432)	(5,735,411)	-	-	-	-	(1,226,140,434)
44	December	31	1	366	0.27%	(5,049,218)	(13,796)	(1,229,203,227)	(4,949,218)	100,000	-	(273)	-	(1,226,153,956)
45	Total					(66,597,881)	(30,980,564)		(58,197,881)	8,400,000	(300,000)	(1,530,601)	173,102	
46	Beginning Balance			274.b				1,198,222,664						(1,200,000,000)
47	Less non Prorated Items			(Line 46 less line 48)				2,396,445,328						-
48	Beginning Balance of Prorated items			(Line 32, Col H)				(1,198,222,664)						(1,200,000,000)
49	Ending Balance			275.k				1,229,203,227						(1,226,153,956)
50	Less non Prorated Items			(Line 49 less line 51)				2,458,406,454						0
51	Ending Balance of Prorated items			(Line 44, Col H)				(1,229,203,227)						(1,226,153,956)
52	Average Balance			([Lines 48 + 51] /2)+([Lines 47 +50)/2])				1,213,712,946						(1,213,076,978)
53	Less FASB 106 & 109 Items			Attachment O, Footnote F				-						-
54	Amount for Attachment O			(Line 52 less line 53)				**1,213,712,946**						**(1,213,076,978)**

Northern States Power Company

Ameren Illinois

Accumulated Deferred Income Taxes

Year Ended December 31, 2016

Rate Year = *Projected 2016*

	Proration Used for Projected Revenue Requirement Calculation								**Proration Used for True-up Revenue Requirement Calculation**					
55	**Account 283**													
56	**Days in Period**					**Averaging with Proration - Projected**			**Averaging Preserving Projected Proration - True-up**					
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**L**	**M**	**N**
57	Month	Days in the Month	Number of Days Prorated	Total Days in Future Portion of Test Period	Proration Amount (C / D)	Projected Monthly Activity	Prorated Projected Monthly Activity (E x F)	Prorated Projected Balance (Cumulative Sum of G)	Actual Monthly Activity	Difference between projected and actual activity	Partially prorate actual activity above Monthly projection	Partially prorate actual activity below Monthly projection but increases ADIT	Partially prorate actual activity below Monthly projection and is a reduction to ADIT	Partially prorated actual balance
58														
59	December 31st balance Prorated Items							-						-
60	January	31	336	366	91.80%	-	-	-	-	-	-	-	-	-
61	February	29	307	366	83.88%	-	-	-	-	-	-	-	-	-
62	March	31	276	366	75.41%	-	-	-	-	-	-	-	-	-
63	April	30	246	366	67.21%	-	-	-	-	-	-	-	-	-
64	May	31	215	366	58.74%	-	-	-	-	-	-	-	-	-
65	June	30	185	366	50.55%	-	-	-	-	-	-	-	-	-
66	July	31	154	366	42.08%	-	-	-	-	-	-	-	-	-
67	August	31	123	366	33.61%	-	-	-	-	-	-	-	-	-
68	September	30	93	366	25.41%	-	-	-	-	-	-	-	-	-
69	October	31	62	366	16.94%	-	-	-	-	-	-	-	-	-
70	November	30	32	366	8.74%	-	-	-	-	-	-	-	-	-
71	December	31	1	366	0.27%	-	-	-	-	-	-	-	-	-
72	Total					-	-		-	-	-	-	-	
73	Beginning Balance			276.b				(38,630,997)						-
74	Less non Prorated Items			(Line 73 less line 75)				(38,630,997)						-
75	Beginning Balance of Prorated items			(Line 59, Col H)				-						-
76	Ending Balance			277.k				(13,802,226)						-
77	Less non Prorated Items			(Line 76 less line 78)				(13,802,226)						-
78	Ending Balance of Prorated items			(Line 71, Col H)				-						-
79	Average Balance			([Lines 75 + 78] /2)+([Lines 74 +77)/2])				(26,216,612)						-
80	Less FASB 106 & 109 Items			Attachment O, Footnote F				-						-
81	Amount for Attachment O			(Line 79 less line 80)				**(26,216,612)**						**-**

Exhibit No. 3

EXHIBIT NO. DVP-8

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 1B
Projected Accumulated Deferred Federal Income Taxes Associated with Pro-rata Liberalized Depreciation

Applicable to the Projections of 2016 and Later and True-ups of 2014 and Later

If the formula rate population is for determining a projected ATRR, enter the year for which the projection is being made on line 1 and populate the remainder of this Attachment 1B with the projected data associated with that year. If the formula rate population is for determining a true-up ATRR for use on Line A of Attachment 6, enter the year for which the true-up is being calculated on line 1 and populate the remainder of this Attachment 1B with the data that was included in Attachment 1B of the projection associated with that year.

Sheet 1 of 3

HYPOTHETICAL POPULATION

Line 1	Projection for Year:	2014	
Line 2	Number of Days in Year:	365	(Enter 365, or for Leap Year enter 366)

Part 1: Account 282, Transmission Plant In Service

Columns 3, 4, 7, and 8 are in dollars (except line 16).

Line	(1) Year	(2) Month	(3) Projected Transmission Plant in Service ADIT	(4) Activity	(5) Remaining Days	(6) Ratio	(7) Activity with Proration	(8) ADIT with Proration
3	2013	Dec	(900,000,000)					(900,000,000)
4	2014	Jan	(910,000,000)	(10,000,000)	335	0.917808	(9,178,082)	(909,178,082)
5	2014	Feb	(920,000,000)	(10,000,000)	307	0.841096	(8,410,959)	(917,589,041)
6	2014	Mar	(930,000,000)	(10,000,000)	276	0.756164	(7,561,644)	(925,150,685)
7	2014	Apr	(940,000,000)	(10,000,000)	246	0.673973	(6,739,726)	(931,890,411)
8	2014	May	(950,000,000)	(10,000,000)	215	0.589041	(5,890,411)	(937,780,822)
9	2014	Jun	(960,000,000)	(10,000,000)	185	0.506849	(5,068,493)	(942,849,315)
10	2014	Jul	(950,000,000)	10,000,000	154	0.421918	4,219,178	(938,630,137)
11	2014	Aug	(940,000,000)	10,000,000	123	0.336986	3,369,863	(935,260,274)
12	2014	Sep	(930,000,000)	10,000,000	93	0.254795	2,547,945	(932,712,329)
13	2014	Oct	(920,000,000)	10,000,000	62	0.169863	1,698,630	(931,013,699)
14	2014	Nov	(910,000,000)	10,000,000	32	0.087671	876,712	(930,136,987)
15	2014	Dec	(930,000,000)	(20,000,000)	1	0.002740	(54,795)	(930,191,782)

16	Total Transmission Plant In Service Net of GSU and GI Plant as a Percentage of Total Transmission Plant In Service:	95.00%
17	Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate a Projected ATRR:	(855,000,000)
18	Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate a Projected ATRR:	(883,682,193)

Explanations:

Col. 3	Projected Account 282 month-end ADIT (excludes cost of removal).
Col. 4	Monthly change in ADIT balance.
Col. 5	Number of days remaining in the year as of and including the last day of the month.
Col. 6	Col. 5 divided by the number of days in the year.
Col. 7	Col. 4 multiplied by col. 6.
Col. 8, Line 3	Amount from col. 3, line 3.
Col. 8, Lines 4-15	Col. 8 of previous month plus col. 7 of current month.
Col. 8, Line 16	Appendix A Line 24 ÷ Appendix A, Line 21 (from the projection population of the formula)
Col. 8, Line 17	Col. 8, Line 3 multiplied by line 16.
Col. 8, Line 18	Col. 8, Line 15 multiplied by line 16.

Northern States Power Company

Exhibit No. DVP-8
Page 2 of 3

Attachment 1B (Continued)
2014
Sheet 2 of 3

HYPOTHETICAL POPULATION

Part 2: Account 282, General Plant

Columns 3, 4, 7, and 8 are in dollars.

Line	(1) Year	(2) Month	(3) Projected General Plant ADIT	(4) Activity	(5) Remaining Days	(6) Ratio	(7) Activity with Proration	(8) ADIT with Proration
1	2013	Dec	(51,000,000)					(51,000,000)
2	2014	Jan	(50,700,000)	300,000	335	0.917808	275,342	(50,724,658)
3	2014	Feb	(50,400,000)	300,000	307	0.841096	252,329	(50,472,329)
4	2014	Mar	(50,100,000)	300,000	276	0.756164	226,849	(50,245,480)
5	2014	Apr	(49,800,000)	300,000	246	0.673973	202,192	(50,043,288)
6	2014	May	(49,500,000)	300,000	215	0.589041	176,712	(49,866,576)
7	2014	Jun	(49,200,000)	300,000	185	0.506849	152,055	(49,714,521)
8	2014	Jul	(49,500,000)	(300,000)	154	0.421918	(126,575)	(49,841,096)
9	2014	Aug	(49,800,000)	(300,000)	123	0.336986	(101,096)	(49,942,192)
10	2014	Sep	(50,100,000)	(300,000)	93	0.254795	(76,438)	(50,018,630)
11	2014	Oct	(50,400,000)	(300,000)	62	0.169863	(50,959)	(50,069,589)
12	2014	Nov	(50,700,000)	(300,000)	32	0.087671	(26,301)	(50,095,890)
13	2014	Dec	(51,000,000)	(300,000)	1	0.002740	(822)	(50,096,712)
14	Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate a Projected ATRR:							(51,000,000)
15	Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate a Projected ATRR:							(50,096,712)

<u>Explanations</u>:

Col. 3	Projected Account 282 month-end ADIT (excludes cost of removal).
Col. 4	Current month change in ADIT balance.
Col. 5	Number of days remaining in the year as of and including the last day of the month.
Col. 6	Col. 5 divided by the number of days in the year.
Col. 7	Col. 4 multiplied by Col. 6.
Col. 8, Line 1	Amount from col. 3, line 1.
Col. 8, Lines 2-13	Col. 8 of previous month plus Col. 7 of current month.
Col. 8, Line 14	Col. 8, Line 1.
Col. 8, Line 15	Col. 8, Line 13.

Northern States Power Company

Attachment 1B (Continued)
2014
Sheet 3 of 3

HYPOTHETICAL POPULATION

Part 3: Account 282, Computer Software - Book Amortization

Columns 3, 4, 7, and 8 are in dollars.
The column and line explanations are as described for Part 2.

Line	(1) Year	(2) Month	(3) Projected Computer Software Book Amount ADIT	(4) Activity	(5) Remaining Days	(6) Ratio	(7) Activity with Proration	(8) ADIT with Proration
1	2013	Dec	39,600,000					39,600,000
2	2014	Jan	39,800,000	200,000	335	0.917808	183,562	39,783,562
3	2014	Feb	40,000,000	200,000	307	0.841096	168,219	39,951,781
4	2014	Mar	40,200,000	200,000	276	0.756164	151,233	40,103,014
5	2014	Apr	40,400,000	200,000	246	0.673973	134,795	40,237,809
6	2014	May	40,600,000	200,000	215	0.589041	117,808	40,355,617
7	2014	Jun	40,800,000	200,000	185	0.506849	101,370	40,456,987
8	2014	Jul	41,000,000	200,000	154	0.421918	84,384	40,541,371
9	2014	Aug	41,200,000	200,000	123	0.336986	67,397	40,608,768
10	2014	Sep	41,400,000	200,000	93	0.254795	50,959	40,659,727
11	2014	Oct	41,600,000	200,000	62	0.169863	33,973	40,693,700
12	2014	Nov	41,800,000	200,000	32	0.087671	17,534	40,711,234
13	2014	Dec	42,000,000	200,000	1	0.002740	548	40,711,782
14	Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate a Projected ATRR:							39,600,000
15	Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate a Projected ATRR:							40,711,782

Part 4: Account 282, Computer Software - Tax Amortization

Columns 3, 4, 7, and 8 are in dollars.
The column and line explanations are as described for Part 2.

Line	(1) Year	(2) Month	(3) Projected Computer Software Tax Amount ADIT	(4) Activity	(5) Remaining Days	(6) Ratio	(7) Activity with Proration	(8) ADIT with Proration
1	2013	Dec	(52,500,000)					(52,500,000)
2	2014	Jan	(52,750,000)	(250,000)	335	0.917808	(229,452)	(52,729,452)
3	2014	Feb	(53,000,000)	(250,000)	307	0.841096	(210,274)	(52,939,726)
4	2014	Mar	(53,250,000)	(250,000)	276	0.756164	(189,041)	(53,128,767)
5	2014	Apr	(53,500,000)	(250,000)	246	0.673973	(168,493)	(53,297,260)
6	2014	May	(53,750,000)	(250,000)	215	0.589041	(147,260)	(53,444,520)
7	2014	Jun	(54,000,000)	(250,000)	185	0.506849	(126,712)	(53,571,232)
8	2014	Jul	(54,250,000)	(250,000)	154	0.421918	(105,479)	(53,676,711)
9	2014	Aug	(54,500,000)	(250,000)	123	0.336986	(84,247)	(53,760,958)
10	2014	Sep	(54,750,000)	(250,000)	93	0.254795	(63,699)	(53,824,657)
11	2014	Oct	(55,000,000)	(250,000)	62	0.169863	(42,466)	(53,867,123)
12	2014	Nov	(55,250,000)	(250,000)	32	0.087671	(21,918)	(53,889,041)
13	2014	Dec	(55,500,000)	(250,000)	1	0.002740	(685)	(53,889,726)
14	Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate a Projected ATRR:							(52,500,000)
15	Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate a Projected ATRR:							(53,889,726)

EXHIBIT NO. DVP-9

Northern States Power Company

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 1C
True-up of Accumulated Deferred Federal Income Taxes Associated with Pro-rata Liberalized Depreciation

Applicable to the True-ups of 2015 and Later

If the formula rate population is for determining a projected ATRR, do not populate this Attachment 1C. If the formula rate population is for determining a true-up ATRR for use on Line A of Attachment 6, enter the year for which the true-up is being calculated on line 1 and populate the remainder of this Attachment 1C with the actual data associated with that year. Use the amounts from lines 17 and 18 of Part 1, and lines 14 and 15 of Parts 2, 3, and 4, in populating Attachment 1 and Attachment 1A as instructed in this Attachment 1C.

Sheet 1 of 3

HYPOTHETICAL POPULATION

Line 1	True-up Year:	2014	(If Populated, Must Match Attachment 1B, Part 1, Line 1)
Line 2	Number of Days in Year:	365	(From Attachment 1B, Part 1, Line 2)

Part 1: Account 282, Transmission Plant In Service

Columns 3 through 12 are in dollars (except line 16).

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line	Year	Month	Actual Transmission Plant In Service ADIT	Actual Activity	Projected Activity from Column (4) of Attachment 1B	Activity Difference	Reversal of Projected Activity Not Realized	Activity Not in Projection	Reversal of Projected Activity Not Realized With Proration	Projected Activity With Proration from Column (7) of Attachment 1B	ADIT Activity for True-up	ADIT Balances for True-up
3	2013	Dec	(900,000,000)									(900,000,000)
4	2014	Jan	(905,000,000)	(5,000,000)	(10,000,000)	5,000,000	5,000,000	0	4,589,041	(9,178,082)	(4,589,041)	(904,589,041)
5	2014	Feb	(915,000,000)	(10,000,000)	(10,000,000)	0	0	0	0	(8,410,959)	(8,410,959)	(913,000,000)
6	2014	Mar	(930,000,000)	(15,000,000)	(10,000,000)	(5,000,000)	0	(5,000,000)	0	(7,561,644)	(12,561,644)	(925,561,644)
7	2014	Apr	(925,000,000)	5,000,000	(10,000,000)	15,000,000	10,000,000	5,000,000	6,739,726	(6,739,726)	5,000,000	(920,561,644)
8	2014	May	(935,000,000)	(10,000,000)	(10,000,000)	0	0	0	0	(5,890,411)	(5,890,411)	(926,452,055)
9	2014	Jun	(945,000,000)	(10,000,000)	(10,000,000)	0	0	0	0	(5,068,493)	(5,068,493)	(931,520,548)
10	2014	Jul	(940,000,000)	5,000,000	10,000,000	(5,000,000)	(5,000,000)	0	(2,109,589)	4,219,178	2,109,589	(929,410,959)
11	2014	Aug	(930,000,000)	10,000,000	10,000,000	0	0	0	0	3,369,863	3,369,863	(926,041,096)
12	2014	Sep	(915,000,000)	15,000,000	10,000,000	5,000,000	0	5,000,000	0	2,547,945	7,547,945	(918,493,151)
13	2014	Oct	(920,000,000)	(5,000,000)	10,000,000	(15,000,000)	(10,000,000)	(5,000,000)	(1,698,630)	1,698,630	(5,000,000)	(923,493,151)
14	2014	Nov	(910,000,000)	10,000,000	10,000,000	0	0	0	0	876,712	876,712	(922,616,439)
15	2014	Dec	(930,000,000)	(20,000,000)	(20,000,000)	0	0	0	0	(54,795)	(54,795)	(922,671,234)

16	Total Transmission Plant In Service Net of GSU and GI Plant as a Percentage of Total Transmission Plant In Service:	95.00%
17	Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate a True-up ATRR:	(855,000,000)
18	Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate a True-up ATRR:	(876,537,672)

Explanations:

Col. 3	Actual Account 282 month-end ADIT (excludes cost of removal).
Col. 4	Monthly change in ADIT balance.
Col. 6	Col. 4 minus col. 5
Col. 7	The portion of the amount in col. 6 included in original projection but not realized.
Col. 8	The portion of the amount in col. 6 not included in original projection.
Col. 9	The amount in col. 7 multiplied by the ratio from col. 6 of Attachment 1B, Part 1.
Col. 11	The sum of col. 8, col. 9, and col. 10.
Col. 12, Line 3	Amount from col. 3, line 3.
Col. 12, Lines 4-15	Col. 12 of previous month plus col. 11 of current month.
Col. 12, Line 16	Appendix A, Line 24 ÷ Appendix A, Line 21 (from the true-up population of the formula)
Col. 12, Line 17	Col. 12, Line 3 multiplied by line 16.
Col. 12, Line 18	Col. 12, Line 15 multiplied by line 16.

Northern States Power Company

Attachment 1C (Continued)
2014
Sheet 2 of 3

HYPOTHETICAL POPULATION

Part 2: Account 282, General Plant

Columns 3 through 12 are in dollars.

Line	(1) Year	(2) Month	(3) Actual General Plant ADIT	(4) Actual Activity	(5) Projected Activity from Column (4) of Attachment 1B	(6) Activity Difference	(7) Reversal of Projected Activity Not Realized	(8) Activity Not in Projection	(9) Reversal of Projected Activity Not Realized With Proration	(10) Projected Activity With Proration from Column (7) of Attachment 1B	(11) ADIT Activity for True-up	(12) ADIT Balances for True-up
1	2013	Dec	(51,000,000)									(51,000,000)
2	2014	Jan	(50,800,000)	200,000	300,000	(100,000)	(100,000)	0	(91,781)	275,342	183,561	(50,816,439)
3	2014	Feb	(50,500,000)	300,000	300,000	0	0	0	0	252,329	252,329	(50,564,110)
4	2014	Mar	(50,100,000)	400,000	300,000	100,000	0	100,000	0	226,849	326,849	(50,237,261)
5	2014	Apr	(50,200,000)	(100,000)	300,000	(400,000)	(300,000)	(100,000)	(202,192)	202,192	(100,000)	(50,337,261)
6	2014	May	(49,900,000)	300,000	300,000	0	0	0	0	176,712	176,712	(50,160,549)
7	2014	Jun	(49,600,000)	300,000	300,000	0	0	0	0	152,055	152,055	(50,008,494)
8	2014	Jul	(49,800,000)	(200,000)	(300,000)	100,000	100,000	0	42,192	(126,575)	(84,383)	(50,092,877)
9	2014	Aug	(50,100,000)	(300,000)	(300,000)	0	0	0	0	(101,096)	(101,096)	(50,193,973)
10	2014	Sep	(50,500,000)	(400,000)	(300,000)	(100,000)	0	(100,000)	0	(76,438)	(176,438)	(50,370,411)
11	2014	Oct	(50,400,000)	100,000	(300,000)	400,000	300,000	100,000	50,959	(50,959)	100,000	(50,270,411)
12	2014	Nov	(50,700,000)	(300,000)	(300,000)	0	0	0	0	(26,301)	(26,301)	(50,296,712)
13	2014	Dec	(51,000,000)	(300,000)	(300,000)	0	0	0	0	(822)	(822)	(50,297,534)

14 Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate a True-up ATRR: (51,000,000)

15 Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate a True-up ATRR: (50,297,534)

Explanations:

Col. 3	Actual Account 282 month-end ADIT (excludes cost of removal).
Col. 4	Monthly change in ADIT balance.
Col. 6	Col. 4 minus col. 5
Col. 7	The portion of the amount in col. 6 included in original projection but not realized.
Col. 8	The portion of the amount in col. 6 not included in original projection.
Col. 9	The amount in col. 7 multiplied by the ratio from col. 6 of Attachment 1B, Part 2, 3 or 4 (as appropriate).
Col. 11	The sum of col. 8, col. 9, and col. 10.
Col. 12, Line 1	Amount from col. 3, line 1.
Col. 12, Lines 2-13	Col. 12 of previous month plus col. 11 of current month.
Col. 12, Line 14	Amount from col. 12, line 1.
Col. 12, Line 15	Amount from col. 12, line 13.

Northern States Power Company

Attachment 1C (Continued)
2014
Sheet 3 of 3

HYPOTHETICAL POPULATION

Part 3: Account 282, Computer Software - Book Amortization

Columns 3 through 12 are in dollars.
The column and line explanations are as described for Part 2.

Line	(1) Year	(2) Month	(3) Actual Computer Software Book Amount ADIT	(4) Actual Activity	(5) Projected Activity from Column (4) of Attachment 1B	(6) Activity Difference	(7) Reversal of Projected Activity Not Realized	(8) Activity Not in Projection	(9) Reversal of Projected Activity Not Realized With Proration	(10) Projected Activity With Proration from Column (7) of Attachment 1B	(11) ADIT Activity for True-up	(12) ADIT Balances for True-up
1	2013	Dec	(51,000,000)									(51,000,000)
2	2014	Jan	(50,700,000)	300,000	200,000	100,000	0	100,000	0	183,562	283,562	(50,716,438)
3	2014	Feb	(50,400,000)	300,000	200,000	100,000	0	100,000	0	168,219	268,219	(50,448,219)
4	2014	Mar	(50,100,000)	300,000	200,000	100,000	0	100,000	0	151,233	251,233	(50,196,986)
5	2014	Apr	(49,800,000)	300,000	200,000	100,000	0	100,000	0	134,795	234,795	(49,962,191)
6	2014	May	(49,500,000)	300,000	200,000	100,000	0	100,000	0	117,808	217,808	(49,744,383)
7	2014	Jun	(49,200,000)	300,000	200,000	100,000	0	100,000	0	101,370	201,370	(49,543,013)
8	2014	Jul	(48,900,000)	300,000	200,000	100,000	0	100,000	0	84,384	184,384	(49,358,629)
9	2014	Aug	(48,600,000)	300,000	200,000	100,000	0	100,000	0	67,397	167,397	(49,191,232)
10	2014	Sep	(48,300,000)	300,000	200,000	100,000	0	100,000	0	50,959	150,959	(49,040,273)
11	2014	Oct	(48,000,000)	300,000	200,000	100,000	0	100,000	0	33,973	133,973	(48,906,300)
12	2014	Nov	(47,700,000)	300,000	200,000	100,000	0	100,000	0	17,534	117,534	(48,788,766)
13	2014	Dec	(47,400,000)	300,000	200,000	100,000	0	100,000	0	548	100,548	(48,688,218)

14 Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate a True-up ATRR: (51,000,000)

15 Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate a True-up ATRR: (48,688,218)

Part 4: Account 282, Computer Software - Tax Amortization

Columns 3 through 12 are in dollars.
The column and line explanations are as described for Part 2.

Line	(1) Year	(2) Month	(3) Actual Computer Software Tax Amount ADIT	(4) Actual Activity	(5) Projected Activity from Column (4) of Attachment 1B	(6) Activity Difference	(7) Reversal of Projected Activity Not Realized	(8) Activity Not in Projection	(9) Reversal of Projected Activity Not Realized With Proration	(10) Projected Activity With Proration from Column (7) of Attachment 1B	(11) ADIT Activity for True-up	(12) ADIT Balances for True-up
1	2013	Dec	(52,500,000)									(52,500,000)
2	2014	Jan	(52,650,000)	(150,000)	(250,000)	100,000	100,000	0	91,781	(229,452)	(137,671)	(52,637,671)
3	2014	Feb	(52,800,000)	(150,000)	(250,000)	100,000	100,000	0	84,110	(210,274)	(126,164)	(52,763,836)
4	2014	Mar	(52,950,000)	(150,000)	(250,000)	100,000	100,000	0	75,616	(189,041)	(113,425)	(52,877,260)
5	2014	Apr	(53,100,000)	(150,000)	(250,000)	100,000	100,000	0	67,397	(168,493)	(101,096)	(52,978,356)
6	2014	May	(53,250,000)	(150,000)	(250,000)	100,000	100,000	0	58,904	(147,260)	(88,356)	(53,066,712)
7	2014	Jun	(53,400,000)	(150,000)	(250,000)	100,000	100,000	0	50,685	(126,712)	(76,027)	(53,142,739)
8	2014	Jul	(53,550,000)	(150,000)	(250,000)	100,000	100,000	0	42,192	(105,479)	(63,287)	(53,206,026)
9	2014	Aug	(53,700,000)	(150,000)	(250,000)	100,000	100,000	0	33,699	(84,247)	(50,548)	(53,256,574)
10	2014	Sep	(53,850,000)	(150,000)	(250,000)	100,000	100,000	0	25,479	(63,699)	(38,220)	(53,294,794)
11	2014	Oct	(54,000,000)	(150,000)	(250,000)	100,000	100,000	0	16,986	(42,466)	(25,480)	(53,320,274)
12	2014	Nov	(54,150,000)	(150,000)	(250,000)	100,000	100,000	0	8,767	(21,918)	(13,151)	(53,333,425)
13	2014	Dec	(54,300,000)	(150,000)	(250,000)	100,000	100,000	0	274	(685)	(411)	(53,333,836)

14 Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate a True-up ATRR: (52,500,000)

15 Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate a True-up ATRR: (53,333,836)

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C., this 11th day of March, 2016.

/s/ Brett K. White
Brett K. White

Attorney for the
Ameren Services Company and
Xcel Energy Services Inc.

Ameren Illinois
Accumulated Deferred Income Taxes
Year Ended December 31, 2016

Rate Year = *Projected 2016*

Line	Proration Used for Projected Revenue Requirement Calculation								Proration Used for True-up R		
1	Account 190										
2	Days in Period					Averaging with Proration - Projected			Averaging Preserving Pr		
	A	B	C	D	E	F	G	H	I	J	K
3	Month	Days in the Month	Number of Days Prorated	Total Days in Future Portion of Test Period	Proration Amount (C / D)	Projected Monthly Activity	Prorated Projected Monthly Activity (E x F)	Prorated Projected Balance (Cumulative Sum of G)	Actual Monthly Activity	Difference between projected and actual activity	Partially prorate actual activity above Monthly projection
4											
5	December 31st balance Prorated Items							53,078,324			
6	January	31	336	366	91.80%	1,746,377	1,603,231	54,681,555	1,500,000	(246,377)	-
7	February	29	307	366	83.88%	1,746,377	1,464,857	56,146,413	2,000,000	253,623	253,623
8	March	31	276	366	75.41%	1,746,377	1,316,940	57,463,353	(100,000)	(1,846,377)	-
9	April	30	246	366	67.21%	1,746,377	1,173,794	58,637,147	500,000	(1,246,377)	-
10	May	31	215	366	58.74%	1,746,377	1,025,877	59,663,024	-	(1,746,377)	-
11	June	30	185	366	50.55%	1,746,377	882,732	60,545,756	750,000	(996,377)	-
12	July	31	154	366	42.08%	1,746,377	734,814	61,280,570	350,000	(1,396,377)	-
13	August	31	123	366	33.61%	1,746,377	586,897	61,867,468	1,750,000	3,623	3,623
14	September	30	93	366	25.41%	1,746,377	443,752	62,311,219	(500,000)	(2,246,377)	-
15	October	31	62	366	16.94%	1,746,377	295,834	62,607,054	250,000	(1,496,377)	-
16	November	30	32	366	8.74%	1,746,377	152,689	62,759,742	50,000	(1,696,377)	-
17	December	31	1	366	0.27%	1,746,377	4,772	62,764,514	2,500	(1,743,877)	-
18	Total					20,956,525	9,686,190		6,552,500	(14,404,025)	257,246

Line				
19	Beginning Balance	234.8.b	177,342,281	
20	Less non Prorated Items	(Line 19 less line 21)	124,263,957	379,098
21	Beginning Balance of Prorated items	(Line 5, Col H)	53,078,324	
22	Ending Balance	234.8.c	189,186,731	
23	Less non Prorated Items	(Line 22 less line 24)	126,422,217	
24	Ending Balance of Prorated items	(Line 17, Col H)	62,764,514	
25	Average Balance	([Lines 21 + 24] /2)+([Lines 20 +23)/2])	183,264,506	
26	Less FASB 106 & 109 Items	Attachment O, Footnote F	1,628,313	
27	Amount for Attachment O	(Line 25 less line 26)	181,636,193	

Northern States Power Company

Ameren Illinois
Accumulated Deferred Income Taxes
Year Ended December 31, 2016

Rate Year = *Projected 2016*

Line	Proration Used for Projected Revenue Requirement Calculation								Proration Used for True-up R		
28	Account 282								This matches Exhibit #2 filed in ER16-197 Revise		
29	Days in Period					Averaging with Proration - Projected			Averaging Preserving Pr		
	A	B	C	D	E	F	G	H	I	J	K
30	Month	Days in the Month	Number of Days Prorated	Total Days in Future Portion of Test Period	Proration Amount (C / D)	Projected Monthly Activity	Prorated Projected Monthly Activity (E x F)	Prorated Projected Balance (Cumulative Sum of G)	Actual Monthly Activity	Difference between projected and actual activity	Partially prorate actual activity above Monthly projection
31											
32	December 31st balance Prorated Items							(1,198,222,664)			
33	January	31	336	366	91.80%	(5,595,391)	(5,136,752)	(1,203,359,416)	(5,795,391)	(200,000)	(200,000)
34	February	29	307	366	83.88%	(5,493,020)	(4,607,533)	(1,207,966,949)	(5,093,020)	400,000	-
35	March	31	276	366	75.41%	(5,704,282)	(4,301,589)	(1,212,268,539)	(5,704,282)	-	-
36	April	30	246	366	67.21%	(5,705,742)	(3,835,007)	(1,216,103,546)	(4,705,742)	1,000,000	-
37	May	31	215	366	58.74%	(5,826,898)	(3,422,905)	(1,219,526,450)	173,102	6,000,000	-
38	June	30	185	366	50.55%	(5,357,351)	(2,707,951)	(1,222,234,401)	(4,557,351)	800,000	-
39	July	31	154	366	42.08%	(5,357,697)	(2,254,332)	(1,224,488,733)	(5,257,697)	100,000	-
40	August	31	123	366	33.61%	(5,297,944)	(1,780,457)	(1,226,269,190)	(5,297,944)	-	-
41	September	30	93	366	25.41%	(5,607,420)	(1,424,836)	(1,227,694,026)	(5,307,420)	300,000	-
42	October	31	62	366	16.94%	(5,867,505)	(993,949)	(1,228,687,975)	(5,967,505)	(100,000)	(100,000)
43	November	30	32	366	8.74%	(5,735,411)	(501,457)	(1,229,189,432)	(5,735,411)	-	-
44	December	31	1	366	0.27%	(5,049,218)	(13,796)	(1,229,203,227)	(4,949,218)	100,000	-
45	Total					(66,597,881)	(30,980,564)		(58,197,881)	8,400,000	(300,000)

Line			
46	Beginning Balance	274.b	1,198,222,664
47	Less non Prorated Items	(Line 46 less line 48)	2,396,445,328
48	Beginning Balance of Prorated items	(Line 32, Col H)	(1,198,222,664)
49	Ending Balance	275.k	1,229,203,227
50	Less non Prorated Items	(Line 49 less line 51)	2,458,406,454
51	Ending Balance of Prorated items	(Line 44, Col H)	(1,229,203,227)
52	Average Balance	([Lines 48 + 51] /2)+([Lines 47 +50)/2])	1,213,712,946
53	Less FASB 106 & 109 Items	Attachment O, Footnote F	-
54	Amount for Attachment O	(Line 52 less line 53)	1,213,712,946

Ameren Illinois

Accumulated Deferred Income Taxes

Year Ended December 31, 2016

Rate Year = *Projected 2016*

Line						Proration Used for Projected Revenue Requirement Calculation			Proration Used for True-up R		
55	Account 283										
56	Days in Period					Averaging with Proration - Projected			Averaging Preserving Pr		
	A	B	C	D	E	F	G	H	I	J	K
57	Month	Days in the Month	Number of Days Prorated	Total Days in Future Portion of Test Period	Proration Amount (C / D)	Projected Monthly Activity	Prorated Projected Monthly Activity (E x F)	Prorated Projected Balance (Cumulative Sum of G)	Actual Monthly Activity	Difference between projected and actual activity	Partially prorate actual activity above Monthly projection
58											
59	December 31st balance Prorated Items							-			
60	January	31	336	366	91.80%	-	-	-	-	-	-
61	February	29	307	366	83.88%	-	-	-	-	-	-
62	March	31	276	366	75.41%	-	-	-	-	-	-
63	April	30	246	366	67.21%	-	-	-	-	-	-
64	May	31	215	366	58.74%	-	-	-	-	-	-
65	June	30	185	366	50.55%	-	-	-	-	-	-
66	July	31	154	366	42.08%	-	-	-	-	-	-
67	August	31	123	366	33.61%	-	-	-	-	-	-
68	September	30	93	366	25.41%	-	-	-	-	-	-
69	October	31	62	366	16.94%	-	-	-	-	-	-
70	November	30	32	366	8.74%	-	-	-	-	-	-
71	December	31	1	366	0.27%	-	-	-	-	-	-
72	Total					-	-		-	-	-

Line	Item	Source	Amount
73	Beginning Balance	276.b	(38,630,997)
74	Less non Prorated Items	(Line 73 less line 75)	(38,630,997)
75	Beginning Balance of Prorated items	(Line 59, Col H)	-
76	Ending Balance	277.k	(13,802,226)
77	Less non Prorated Items	(Line 76 less line 78)	(13,802,226)
78	Ending Balance of Prorated items	(Line 71, Col H)	-
79	Average Balance	([Lines 75 + 78] /2)+([Lines 74 +77)/2])	(26,216,612)
80	Less FASB 106 & 109 Items	Attachment O, Footnote F	-
81	Amount for Attachment O	(Line 79 less line 80)	(26,216,612)

evenue Requirement Calculation

ojected Proration - True-up

L	M	N
Partially prorate actual activity below Monthly projection but increases ADIT	Partially prorate actual activity below Monthly projection and is a reduction to ADIT	Partially prorated actual balance
		54,000,000
226,182	-	55,377,049
-	-	57,095,529
-	(100,000)	56,995,529
837,729	-	57,331,595
1,025,877	-	57,331,595
503,633	-	57,710,693
587,547	-	57,857,961
-	-	58,448,481
-	(500,000)	57,948,481
253,485	-	57,990,831
148,317	-	57,995,203
4,765	-	57,995,209
3,587,535	(600,000)	
		180,000,000
		126,000,000
		54,000,000
		192,000,000
		134,004,791
		57,995,209
		186,000,000
		1,600,000
		184,400,000

evenue Requirement Calculation

d 3/3/16

ojected Proration - True-up

L	M	N
Partially prorate actual activity below Monthly projection but increases ADIT	Partially prorate actual activity below Monthly projection and is a reduction to ADIT	Partially prorated actual balance
		(1,200,000,000)
-	-	(1,205,336,752)
(335,519)	-	(1,209,608,767)
-	-	(1,213,910,356)
(672,131)	-	(1,217,073,232)
-	173,102	(1,216,900,130)
(404,372)	-	(1,219,203,709)
(42,077)	-	(1,221,415,964)
-	-	(1,223,196,421)
(76,230)	-	(1,224,545,028)
-	-	(1,225,638,977)
-	-	(1,226,140,434)
(273)	-	(1,226,153,956)
(1,530,601)	173,102	
		(1,200,000,000)
		-
		(1,200,000,000)
		(1,226,153,956)
		0
		(1,226,153,956)
		(1,213,076,978)
		-
		(1,213,076,978)

evenue Requirement Calculation

ojected Proration - True-up

L	M	N
Partially prorate actual activity below Monthly projection but increases ADIT	Partially prorate actual activity below Monthly projection and is a reduction to ADIT	Partially prorated actual balance
		-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
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-	-	
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Document Content(s)

Northern States Power Company
NSPM Minnesota Retail - Electric
IRS Pro-Rate Method Accumulated Deferred Tax Adjustment
Including NOL Annual Deferred at Last Authorized Rate of Return
Test Year Ending December 31, 2016

At Last Authorized ROE

	Days to Prorate	Prorate Factor	Total Company Plant Deferred *	Total Company Prorated Plant Deferred *	MN Jurisdiction Prorated Plant Deferred	MN Jurisdiction Prorated Plant Deferred	MN Jurisdiction NOL	MN Jurisdiction Prorated NOL	Monthly Expense (2016)	Prorated Monthly Expense (2016)
RIS Annual Deferred Tax Expense			111,135,327		95,083,231		120,693,096		215,776,327	
January	335	91.78%	9,261,277	8,500,076	7,923,603	7,272,348	10,057,758	9,231,093	17,981,361	16,503,441
February	307	84.11%	9,261,277	7,789,622	7,923,603	6,664,510	10,057,758	8,459,539	17,981,361	15,124,049
March	276	75.62%	9,261,277	7,003,048	7,923,603	5,991,546	10,057,758	7,605,318	17,981,361	13,596,864
April	246	67.40%	9,261,277	6,241,847	7,923,603	5,340,291	10,057,758	6,778,653	17,981,361	12,118,944
May	215	58.90%	9,261,277	5,455,273	7,923,603	4,667,328	10,057,758	5,924,433	17,981,361	10,591,760
June	185	50.68%	9,261,277	4,694,072	7,923,603	4,016,073	10,057,758	5,097,768	17,981,361	9,113,840
July	154	42.19%	9,261,277	3,907,498	7,923,603	3,343,109	10,057,758	4,243,547	17,981,361	7,586,656
August	123	33.70%	9,261,277	3,120,924	7,923,603	2,670,146	10,057,758	3,389,327	17,981,361	6,059,472
September	93	25.48%	9,261,277	2,359,723	7,923,603	2,018,891	10,057,758	2,562,662	17,981,361	4,581,552
October	62	16.99%	9,261,277	1,573,148	7,923,603	1,345,927	10,057,758	1,708,441	17,981,361	3,054,368
November	32	8.77%	9,261,277	811,948	7,923,603	694,672	10,057,758	881,776	17,981,361	1,576,448
December	1	0.27%	9,261,277	25,373	7,923,603	21,709	10,057,758	27,556	17,981,361	49,264
Total Days									Total	99,956,659

Pro-Rate Method BOY/EOY Average	49,978,330
BOY/EOY Average	107,888,164
Rate Base Adjustment	57,909,834
Composite Tax Rate	41.37%
Weighted Cost of STD	0.02%
Weighted Cost of LTD	2.22%
Weighted Cost of Debt	2.24%
Weighted Cost of Equity	5.10%
Required Rate of Return	**7.34%**
Equity Return Tax RR	**3.60%**
RB Revenue Requirement Factor	10.94%
Annual Revenue Requirement Impact	6,334,536

* Tie to Exhibit__(LHP-1), Schedule 11

Northern States Power Company
NSPM Minnesota Retail - Electric
IRS Pro-Rate Method Accumulated Deferred Tax Adjustment
Including NOL Annual Deferred
Period Ending December 31, 2017

	Days to Prorate	Prorate Factor	Total Company Plant Deferred *	Total Company Prorated Plant Deferred *	MN Jurisdiction Prorated Plant Deferred	MN Jurisdiction Prorated Plant Deferred	MN Jurisdiction NOL	MN Jurisdiction Prorated NOL	2017 Monthly Expense	Prorated Monthly Expense
RIS Annual Deferred Tax Expense			77,182,080		62,998,563			0	62,998,563	
January	335	91.78%	6,431,840	5,903,196	5,249,880	4,818,383	-	-	5,249,880	4,818,383
February	307	84.11%	6,431,840	5,409,794	5,249,880	4,415,653	-	-	5,249,880	4,415,653
March	276	75.62%	6,431,840	4,863,528	5,249,880	3,969,772	-	-	5,249,880	3,969,772
April	246	67.40%	6,431,840	4,334,884	5,249,880	3,538,275	-	-	5,249,880	3,538,275
May	215	58.90%	6,431,840	3,788,618	5,249,880	3,092,395	-	-	5,249,880	3,092,395
June	185	50.68%	6,431,840	3,259,974	5,249,880	2,660,898	-	-	5,249,880	2,660,898
July	154	42.19%	6,431,840	2,713,708	5,249,880	2,215,018	-	-	5,249,880	2,215,018
August	123	33.70%	6,431,840	2,167,442	5,249,880	1,769,138	-	-	5,249,880	1,769,138
September	93	25.48%	6,431,840	1,638,798	5,249,880	1,337,641	-	-	5,249,880	1,337,641
October	62	16.99%	6,431,840	1,092,532	5,249,880	891,760	-	-	5,249,880	891,760
November	32	8.77%	6,431,840	563,887	5,249,880	460,263	-	-	5,249,880	460,263
December	1	0.27%	6,431,840	17,621	5,249,880	14,383	-	-	5,249,880	14,383
Total Days									Total	29,183,581

	Requested	Last Authorized
Pro-Rate Method BOY/EOY Average	14,591,791	
BOY/EOY Average	31,499,282	
Rate Base Adjustment	**16,907,491**	
Composite Tax Rate	41.37%	41.37%
Weighted Cost of STD	0.05%	0.05%
Weighted Cost of LTD	2.21%	2.21%
Weighted Cost of Debt	2.26%	2.26%
Weighted Cost of Equity	5.25%	5.10%
Required Rate of Return	**7.51%**	**7.36%**
Equity Return Tax RR	**3.70%**	**3.60%**
RB Revenue Requirement Factor	**11.21%**	**10.96%**
Annual Revenue Requirement Impact	**1,896,084**	**1,852,827**

* Tie to Exhibit__(LHP-1), Schedule 11

Northern States Power Company
NSPM Minnesota Retail - Electric
IRS Pro-Rate Method Accumulated Deferred Tax Adjustment
Including NOL Annual Deferred
Period Ending December 31, 2018

									2018	
RIS Annual Deferred Tax Expense			73,263,890		60,234,388			0	60,234,388	
	Days to Prorate	Prorate Factor	Total Company Plant Deferred *	Total Company Prorated Plant Deferred *	MN Jurisdiction Prorated Plant Deferred	MN Jurisdiction Prorated Plant Deferred	MN Jurisdiction NOL	MN Jurisdiction Prorated NOL	Monthly Expense	Prorated Monthly Expense
January	335	91.78%	6,105,324	5,603,517	5,019,532	4,606,968	-	-	5,019,532	4,606,968
February	307	84.11%	6,105,324	5,135,163	5,019,532	4,221,908	-	-	5,019,532	4,221,908
March	276	75.62%	6,105,324	4,616,629	5,019,532	3,795,592	-	-	5,019,532	3,795,592
April	246	67.40%	6,105,324	4,114,821	5,019,532	3,383,027	-	-	5,019,532	3,383,027
May	215	58.90%	6,105,324	3,596,287	5,019,532	2,956,711	-	-	5,019,532	2,956,711
June	185	50.68%	6,105,324	3,094,479	5,019,532	2,544,147	-	-	5,019,532	2,544,147
July	154	42.19%	6,105,324	2,575,945	5,019,532	2,117,830	-	-	5,019,532	2,117,830
August	123	33.70%	6,105,324	2,057,411	5,019,532	1,691,514	-	-	5,019,532	1,691,514
September	93	25.48%	6,105,324	1,555,603	5,019,532	1,278,949	-	-	5,019,532	1,278,949
October	62	16.99%	6,105,324	1,037,069	5,019,532	852,633	-	-	5,019,532	852,633
November	32	8.77%	6,105,324	535,261	5,019,532	440,069	-	-	5,019,532	440,069
December	1	0.27%	6,105,324	16,727	5,019,532	13,752	-	-	5,019,532	13,752
Total Days									Total	27,903,099

Pro-Rate Method BOY/EOY Average	13,951,549	
BOY/EOY Average	30,117,194	
Rate Base Adjustment	16,165,645	
	Requested	**Last Authorized**
Composite Tax Rate	41.37%	41.37%
Weighted Cost of STD	0.05%	0.05%
Weighted Cost of LTD	2.21%	2.21%
Weighted Cost of Debt	2.26%	2.26%
Weighted Cost of Equity	5.25%	5.10%
Required Rate of Return	**7.51%**	**7.36%**
Equity Return Tax RR	**3.70%**	**3.60%**
RB Revenue Requirement Factor	**11.21%**	**10.96%**
Annual Revenue Requirement Impact	**1,812,890**	**1,771,531**

* Tie to Exhibit__(LHP-1), Schedule 11

Internal Revenue Service

Number: **201541010**
Release Date: 10/9/2015

Index Number: 167.22-01

Department of the Treasury
Washington, DC 20224

Third Party Communication: None
Date of Communication: Not Applicable

Person To Contact:
, ID No.

Telephone Number:

Refer Reply To:
CC:PSI:B06
PLR-143241-14

Date:
July 06, 2015

LEGEND:

Taxpayer =

Parent =

State A =
State B =
Commission A =
Commission B =
Commission C =
Operator =
Year A =
Case A =
Case B =
Case C =
Date X =
Director =

Dear :

This letter responds to Parent's request, made on behalf of Taxpayer, dated January 9, 2015, for a ruling on the application of the normalization rules to certain regulatory procedures applied in State as described below.

The representations set out in your letter follow.

Taxpayer, a wholly-owned subsidiary of Parent, is primarily engaged in the business of generating, transmitting, distributing, and selling electric power to customers in State A and State B. It is subject to regulation by Commission A, Commission B, and Commission C with respect to terms and conditions of services, including the rates it may charge for its services. All three Commissions establish Taxpayer's rates based on Taxpayer's costs, including a provision for a return on the capital employed by Taxpayer in its regulated business.

The law of State A provides a process under which a utility may recover its costs relating to projects such as new electric generation facilities as a stand-alone rate adjustment added to customers' base rates. As relevant to this ruling request, the process for setting the rates involves two components. First, a taxpayer files estimated projections of all factors, including Accumulated Deferred Federal Income Taxes (ADFIT), relevant to the costs associated with the facility that is the subject of the rate adjustment. Rate base for this purpose is calculated using an average of the thirteen projected end of month balances of the components of rate base. The rate adjustment computed using these projections goes into effect at the beginning of the test period. The test period is a twelve month period. The anticipated collections from rate payers, the actual cost incurred with respect to the generating facility and any differences between anticipated amounts and actual amounts are reconciled by a "true-up" mechanism at the end of the test year. Under this mechanism, the reconciliation amount is either charged to ratepayers (if actual revenues are below estimates) or credited to ratepayers (if actual revenues exceed estimates) as part of the rates established for the forthcoming rate year. For both under and over collections, a carrying charge is imposed.

Taxpayer owns and operates electric transmission lines in several states, including State A and State B. These lines are integrated into Operator, a regional transmission operator. The rates that Taxpayer may charge its customers for these transmission services are set using a formula approved by Commission C. The formula rates are calculated using a methodology similar to that used to calculate the rate adjustments, inasmuch as the formula rates are calculated using projected costs to establish rates during the period for which rates are being set and a true-up based on over or under recoveries that are reflected in a subsequent rate year. The rates are determined by application of the formula approved by Commission C and go into effect with no additional action by Commission C.

Taxpayer claims accelerated depreciation on its tax returns to the extent permitted by the Internal Revenue Code. Taxpayer normalizes the federal income taxes deferred as a result of its use of accelerated depreciation and thus maintains an ADFIT balance on its regulatory books. In ratemaking proceedings before Commission A to authorize rate adjustments as well as in calculation of the formula rates, rate base is reduced by the calculated ADFIT balance. In calculating its ADFIT balance for purposes of both the projection and true-up elements of the rate adjustment calculations, Taxpayer followed the same averaging conventions it used for the other components of rate base. However, for prior formula rate filings, Taxpayer had calculated its ADFIT balance by an average of the beginning and ending balances notwithstanding that it used a 13-month average for computation of the plant portion of rate base. In those prior cases, the averages are calculated in accordance with the provisions of the Commission-approved template and the differences in averaging conventions are required by the regulations adopted by Commission C.

Section 1.167(l)-1(h)(6) of the Income Tax Regulations requires that a proration methodology be used by Taxpayer to calculate its applicable ADFIT balance for future test periods. Prior to Year A, Taxpayer had not used the proration methodology either in estimating its projected ADFIT balance or for the calculation of ADFIT for purposes of the true-up. Members of Taxpayer's tax department became concerned about the normalization implications of not using the proration formula during Year A. In filing Case A, Case B, and Case C, Taxpayer incorporated the proration methodology into the calculation of its projected ADFIT balance. In addition, Taxpayer incorporated the proration methodology into the calculation of the true-up in Case B. The staff of Commission A did not agree that the test period used for the rate adjustment ratemaking was a future test period and therefore asserted that the proration methodology was not required. In each of these cases, Commission A approved the use of the proration methodology in the projected ADFIT balance but denied its use in the true-up. When Commission A approved the use of the proration methodology for the projected ADFIT balance, it revised a portion of the Taxpayer's cash working capital allowance to reflect the adoption of the proration methodology. The adjusted portion was intended to compensate Taxpayer for the lag in time between when expenditures are made for services by Taxpayer and when collections for those services are received by Taxpayer. Commission A concluded that the item in the cash working capital allowance was duplicative of the effect of the proration methodology and was thus unnecessary. Due to the uncertainty surrounding the application of the proration methodology and the adjustment to cash working capital, Commission A directed Taxpayer to seek this ruling from the Internal Revenue Service.

Both Commission A and Commission C at all times have required that all public utilities under their respective jurisdictions use normalized methods of accounting.

Taxpayer requests that we rule as follows:

1. The proration methodology requirement does not apply to stand-alone rate adjustment ratemaking and to the Commission C formula rates even if they involve future test periods.
2. The estimated projection component of both the stand-alone rate adjustment ratemaking and the formula rate does not employ a future test period within the meaning of § 1.167(l)-1(h)(6)(ii) and therefore Taxpayer is not required to use the proration methodology in order to comply with the normalization rules.

3. The true-up component of both the stand-alone rate adjustment ratemaking and the formula rate does not employ a future test period within the meaning of § 1.167(l)-1(h)(6)(ii) and therefore Taxpayer is not required to use the proration methodology in order to comply with the normalization rules.
4. In Taxpayer's stand-alone rate adjustment proceedings, an adjustment to eliminate from the Taxpayer's cash working capital allowance any provision for accelerated depreciation-related ADFIT if the proration methodology is employed does not conflict with the normalization rules.
5. In order to comply with the consistency requirement of the normalization rules, it is not necessary that the Taxpayer use the same averaging convention it uses in computing the other elements of rate base in computing its ADFIT balance for purposes of the formula rates.
6. If the Service rules adversely with respect to Rulings 1, 2, or 3, above, any failure by Taxpayer to employ the proration methodology prior to the proceedings in Cases A, B, or C or the effective date approved by Commission C for the requested modification of the formula rates was not a violation of the normalization rules requiring sanctions for such violation.
7. In the event that the Service rules adversely with respect to Ruling 5, above, Taxpayer's failure to comply with the consistency requirement in connection with its formula rates prior to the effective date approved by Commission C for the requested modification of the formula rates was not a violation of the normalization rules.

Law and Analysis

Issues 1 and 2

Former section 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former section 167(l)(3)(G) in a manner consistent with that found in section 168(i)(9)(A). Section 1.167(1)-1(a)(1) of the Income Tax Regulations provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 168(f)(2) of the Code provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, section 168(i)(9)(A) requires that a taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes of establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under section 168(i)(9)(A)(ii), if the amount allowable as a deduction under section 168 differs from the amount that-would be allowable as a deduction under section 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under section 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 1.167(l)-1(h)(6) sets forth additional normalization requirements with respect to public utility property. Under § 1.167(l)-1(h)(6)(i), a taxpayer does not use a normalization method of accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes excluded from the rate base, or treated as cost-free capital, exceeds the amount of the reserve for the period used in determining the taxpayer's ratemaking tax expense. Section 1.167(l)-1(h)(6)(ii) also provides the procedure for determining the amount of the reserve for deferred taxes to be excluded from rate base or to be included as no-cost capital. If, in determining depreciation for ratemaking tax expense, a period (the "test period") is used which is part historical and part future, then the amount of the reserve account for this period is the amount of the reserve at the end of the historical portion of the period and a pro rata amount of any projected increase to be credited to the account during the future portion of the period. The pro rata amount of any increase during the future portion of the period is determined by multiplying the increase by a fraction, the numerator of which is the number of days remaining in the period at the time the increase is to accrue, and the denominator of which is the total number of days in the future portion of the period.

Section 1.167(l)-1(h)(6)(i) makes it clear that the reserve excluded from rate base must be determined by reference to the same period as is used in determining ratemaking tax expense. A taxpayer may use either historical data or projected data in calculating these two amounts, but it must be consistent. As explained in section 1.167(l)-1(a)(1), the rules provided in section 1.167(l)-1(h)(6)(i) are to insure that the same time period is used to determine the deferred tax reserve amount resulting from the use of an accelerated method of depreciation for cost of service purposes and the reserve amount that may be excluded from the rate base or included in no-cost capital in determining such cost of services.

If a taxpayer chooses to compute its ratemaking tax expense and rate base exclusion amount using projected data then it must use the formula provided in section 1.167(l)-1(h)(6)(ii) to calculate the amount of deferred taxes subject to exclusion from the rate base. This formula prorates the projected accruals to the reserve so as to account for the actual time these amounts are expected to be in the reserve. As explained in § 1.167(l)-1(a)(1), the formula in section 1.167(l)-1(h)(6)(ii) provides a method to determine the period of time during which the taxpayer will be treated as having received amounts credited or charged to the reserve account so that the disallowance of earnings with respect to such amounts through rate base exclusion or treatment as no-cost capital will take into account the factor of time for which such amounts are held by the taxpayer.

The purpose of the proration formula is to prevent the immediate flow-through of the benefits of accelerated depreciation to ratepayers. The proration formula stops flow-through by limiting the deferred tax reserve accruals that may be excluded from rate base, and thus the earnings on rate base that may be disallowed, according to the length of time these accruals are actually in the reserve account.

The effectiveness of § 1.167(l)-1(h)(6)(ii) in resolving the timing issue has been questioned by its failure to define some key terms. Nowhere does this provision state what is meant by the terms "historical" and "future" in relation to the period for determining depreciation for ratemaking tax expense (the "test period"). One interpretation focuses on the type or quality of the data used in the ratemaking process. According to this interpretation, the historical period is that portion of the test period for which actual data is used, while the portion of the period for which data is estimated is the future period. The second interpretation focuses on when the utility rates become effective. Under this interpretation, the historical period is that portion of the test period before rates go into effect, while the portion of the test period after the effective date of the rate order is the future period.

The first interpretation, which focuses on the quality of the ratemaking data, is an attractive one. It proposes a simple rule, easy to follow and to enforce: any portion of the reserve for deferred taxes based on estimated data must be prorated in determining the amount to be deducted from rate base. The actual passage of time between the date ratemaking data is submitted and the date rates become effective is of no importance. But this interpretation of the regulations achieves simplicity at the expense of precision; in other words, it is overbroad. The proration of all estimated deferred tax data does serve to magnify the benefits of accelerated depreciation to the utility, but this is not the purpose of normalization. Congress was explicit: normalization "in no way diminishes whatever power the [utility regulatory] agency may have to require that the deferred taxes reserve be excluded from the base upon which the utility's permitted rate of return is calculated." H.R. Rep. No. 413, 91st Cong., 1st Sess. 133 (1969).

In contrast, the second interpretation of section 1.167(l)-1(h)(6)(ii) of the regulations is consistent with the purpose of normalization, which is to preserve for regulated utilities the benefits of accelerated depreciation as a source of cost-free capital. The availability of this capital is ensured by prohibiting flow-through. But whether or not flow-through can even be accomplished by means of rate base exclusions depends primarily on whether, at the time rates become effective, the amounts originally projected to accrue to the deferred tax reserve have actually accrued.

If rates go into effect before the end of the test period, and the rate base reduction is not prorated, the utility commission is denying a current return for accelerated depreciation benefits the utility is only projected to have. This procedure is a form of flow-through, for current rates are reduced to reflect the capital cost savings of accelerated depreciation deductions not yet claimed or accrued by the utility. Yet projected data is often necessary in determining rates, since historical data by itself is rarely an accurate indication of future utility operating results. Thus, the regulations provide that as long as the portion of the deferred tax reserve based on projected (future estimated) data is prorated according to the formula in section 1.167(l)-1(h)(6)(ii), a regulator may deduct this reserve from rate base in determining a utility's allowable return. In other words, a utility regulator using projected data in computing ratemaking tax expense and rate base exclusion must account for the passage of time if it is to avoid flow-through.

But if rates go into effect after the end of the test period, the opportunity to flow through the benefits of future accelerated depreciation to current ratepayers is gone, and so too is the need to apply the proration formula. In this situation, the only question that is important for the purpose of rate base exclusion is the amount in the deferred tax reserve, whether actual or estimated. Once the future period, the period over which accruals to the reserve were projected, is no longer future, the question of when the amounts in the reserve accrued is no longer relevant (at the time the new rate order takes effect, the projected increases have accrued, and the amounts to be excluded from rate base are no longer projected but historical, even though based on estimates).

There are two kinds of ratemaking at issue here, with identical components. For both the stand-alone rate adjustment and the formula rates, Taxpayer estimates the various components of rate base. Rates go into effect as of the beginning of the service year.[1] As such, the rates are in effect during the test year and the proration formula must be used. The addition of the true up increases the ultimate accuracy of the rates but does not convert a future test period into a historical test period as those terms are used in the normalization regulations. Therefore, Taxpayer is required to apply the proration formula in calculating accumulated deferred income taxes for purposes of calculating rate base.

<u>Issue 3</u>

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[1] We note that, because Taxpayer is using estimated data for the test period, the test period at issue here constitutes a “future test period” under the first interpretation discussed above as well.

As discussed above, where a taxpayer computes its ratemaking tax expense and rate base exclusion amount using projected data then must use the proration formula provided in section 1.167(l)-1(h)(6)(ii) to calculate the amount of deferred taxes subject to exclusion from the rate base. This formula prorates the projected accruals to the reserve so as to account for the actual time these amounts are expected to be in the reserve. As explained in § 1.167(l)-1(a)(1), the formula in section 1.167(l)-1(h)(6)(ii) provides a method to determine the period of time during which the taxpayer will be treated as having received amounts credited or charged to the reserve account so that the disallowance of earnings with respect to such amounts through rate base exclusion or treatment as no-cost capital will take into account the factor of time for which such amounts are held by the taxpayer.

The purpose of the proration formula is to prevent the immediate flow-through of the benefits of accelerated depreciation to ratepayers. The proration formula stops flow-through by limiting the deferred tax reserve accruals that may be excluded from rate base, and thus the earnings on rate base that may be disallowed, according to the length of time these accruals are actually in the reserve account.

In contrast to the projections discussed above, the true-up component is determined by reference to a purely historical period and there is no need to use the proration formula to calculate the differences between Taxpayer's projected ADFIT balance and the actual ADFIT balance during the period. In calculating the true-up, proration applies to the original projection amount but the actual amount added to the ADFIT over the test year is not modified by application of the proration formula.

Issue 4

In Taxpayer's stand-alone rate adjustment proceedings, Commission A adjusted the already-approved cash working capital allowance specifically to mitigate the effect of the use of the proration methodology, finding the effects duplicative. In general, taxpayers may not adopt any accounting treatment that directly or indirectly circumvents the normalization rules. See generally, § 1.46-6(b)(2)(ii) (In determining whether, or to what extent, the investment tax credit has been used to reduce cost of service, reference shall be made to any accounting treatment that affects cost of service); Rev. Proc 88-12, 1988-1 C.B. 637, 638 (It is a violation of the normalization rules for taxpayers to adopt any accounting treatment that, directly or indirectly flows excess tax reserves to ratepayers prior to the time that the amounts in the vintage accounts reverse). Here, Commission A adjusted the cash working capital allowance specifically to mitigate the effect of the application of the proration methodology. This is inconsistent with the normalization rules. We do not hold that the normalization rules require a similar type of cash working capital adjustment in all cases; we hold only that, where, as here, it is adjusted or removed in an attempt to mitigate the effects of the application of the proration methodology or similar normalization rule, that adjustment or removal is not permitted under the normalization rules.

Issue 5

Former section 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former section 167(l)(3)(G) in a manner consistent with that found in section 168(i)(9)(A). Section 1.167(1)-1(a)(1) of the Income Tax Regulations provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 168(f)(2) of the Code provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, section 168(i)(9)(A) requires that a taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes of establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under section 168(i)(9)(A)(ii), if the amount allowable as a deduction under section 168 differs from the amount that-would be allowable as a deduction under section 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under section 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) of the Code provides that one way the requirements of section 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under section 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under section 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base.

In order to satisfy the requirements of §168(i)(9)(B), there must be consistency in the treatment of costs for rate base, regulated depreciation expense, tax expense, and deferred tax revenue purposes. Here, rate base, depreciation expense, and accumulated deferred income taxes are all calculated in consistent fashion – all are averaged over the same period. While there are minor differences in the convention used to average all elements of rate base including depreciation expense on the one hand, and ADFIT on the other, for purposes of §168(i)(9)(B), it is sufficient that both are determined by averaging and both are determined over the same period of time. Thus, the calculation of average rate base and accumulated deferred income taxes as described above complies with the consistency requirement of §168(i)(9)(B).

Because of the conclusion reached above, Taxpayer's seventh issue is moot and will not be considered further.

Issue 6

Because the Service has ruled in Issue 1 and 2 that Taxpayer was required to use the proration formula applicable to future test periods for the projected revenue requirement, prospectively adhering to the Service's interpretation of § 1.167(l)-1(h)(6)(ii) require adjustments to conform to this ruling. Any rates that have been calculated using procedures inconsistent with this ruling ("nonconforming rates") which are or which have been in effect and which, under applicable state or federal regulatory law, can be adjusted or corrected to conform to the requirements of this ruling, must be so adjusted or corrected. Where nonconforming rates cannot be adjusted or corrected to conform to the requirements of this ruling due to the operation of state or federal regulatory law, then such correction must be made in the next regulatory filing or proceeding in which Taxpayer's rates are considered. Specifically, the current timing of Taxpayer's stand-alone rate adjustment filings with Commission A will accommodate all adjustments or corrections to any prior estimated projections or true-ups necessary to conform to the requirements of this ruling in rates having an effective date no later Date X, including Case A, Case B, and Case C. In addition, Taxpayer has already sought an order from Commission C to make the necessary changes to the rate templates, not simply unilaterally adjusting the calculations (or the manner in which the templates are completed) in the next annual projections or true-up adjustments. If Taxpayer must request these changes through a filing with Commission C, Taxpayer has represented that it will make a filing with Commission C to amend its formula rate template within six months of receipt of this ruling letter, requesting that Commission C apply a methodology in accordance with this letter using an effective date of the first month following the date of the filing made with Commission C. Following Commission C's order in that filing, Taxpayer will prospectively apply the methodology consistent with this letter approved by Commission C. Until Commission C acts on the filing, Taxpayer will continue to use the methodology described above.

Section 168(f)(2) of the Code provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting. However, in the legislative history to the enactment of the normalization requirements of the Investment Tax Credit, Congress has stated that it hopes that sanctions will not have to be imposed and that disallowance of the tax benefit (there, the ITC) should be imposed only after a regulatory body has required or insisted upon such treatment by a utility. See Senate Report No. 92-437, 92nd Cong., 1st Sess. 40-41 (1971), 1972-2 C.B. 559, 581.

Here, Taxpayer has received stand-alone rate adjustments from Commission A without application of the proration methodology as required. In addition, Taxpayer used a template approved by Commission C to calculate formula-based rates. Both Commission A and Commission C have, at all times, required that utilities under their respective jurisdictions use normalization methods of accounting. Taxpayer also intended at all times to comply with the normalization rules. As concluded above, Taxpayer was required to use the proration methodology in these ratemaking proceedings. However because Commissions A and C as well as Taxpayer at all times sought to comply, and because Taxpayer will take the corrective actions described above, it is not currently appropriate to apply the sanction of denial of accelerated depreciation to Taxpayer.

Conclusions

1. The proration methodology requirement applies to all future test periods.
2. The estimated projection component of both the stand-alone rate adjustment ratemaking and the formula rate does employ a future test period within the meaning of § 1.167(l)-1(h)(6)(ii) and therefore Taxpayer is required to use the proration methodology in order to comply with the normalization rules.
3. The true-up component of both the stand-alone rate adjustment ratemaking and the formula rate does not employ a future test period within the meaning of § 1.167(l)-1(h)(6)(ii) and therefore Taxpayer is not required to use the proration methodology in order to comply with the normalization rules.
4. In Taxpayer's stand-alone rate adjustment proceedings, an adjustment to eliminate from the Taxpayer's cash working capital allowance any provision for accelerated depreciation-related ADFIT if the proration methodology is employed does conflict with the normalization rules.
5. In order to comply with the consistency requirement of the normalization rules, it is not necessary that the Taxpayer use the same averaging convention it uses in computing the other elements of rate base in computing its ADFIT balance for purposes of the formula rates.

6. The Service rules adversely with respect to Rulings 1 and 2, above. Any failure by Taxpayer to employ the proration methodology prior to the proceedings in Cases A, B, or C or the effective date approved by Commission C for the requested modification of the formula rates was not a violation of the normalization rules requiring sanctions for such violation.
7. Because the Service rules favorably with respect to Ruling 5, above, Taxpayer's requested Ruling 7 is moot.

Except as specifically determined above, no opinion is expressed or implied concerning the Federal income tax consequences of the matters described above.

This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. We are also sending a copy of this letter ruling to the Director.

Sincerely,

Peter C. Friedman
Senior Technician Reviewer, Branch 6
Office of the Associate Chief Counsel
(Passthroughs & Special Industries)

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-15-826		
Response To:	Department of Commerce	Information Request No.	159
Requestor:	Nancy Campbell, Angela Byrne, Dale Lusti		
Date Received:	March 17, 2016		

Question:

Reference: N/A
Subject: Federal and State Research & Experimentation Credits

A. Please identify, explain and provide all supporting calculations for all Federal and State Research and Experimentation Credits for the years 2016 and 2020 for both the three-year and five-year rate plans.

B. If the Company did not include any Federal and State Research & Experimentation Credits, please explain why that is reasonable.

C. Please provide all adjustments assuming all Federal and State Research and Experimentation Credits are required to be returned to customers for the years 2016 and 2020 for both the three-year and five-year rate plans.

Response:

A. Only a Minnesota research and experimentation (R&E) credit was included in the three-year and five-year rate plans since, at the time of filing, the Federal research credit had expired as of December 31, 2014. Please see further explanation under response part B.

As stated under Minn. Stat. § 290.068, Subd. 2, qualifying expenditures follow the requirements of the Federal R&E credit with the exception that only costs incurred within the state of Minnesota qualify for the Minnesota credit. Although the Federal research credit had expired, the Minnesota credit is a permanent credit and can still rely on the definitions provided in IRC Section 41. Under IRC Section 41(b), qualified expenses for calculation of the credit may include employee wages, supplies used to conduct qualified research, and contract research expenses.

In order to determine qualifying expenses for both Federal and Minnesota purposes, Xcel Energy uses a project-based approach to determine projects and associated activities that qualify for the R&E credit. A four-part test is used in accordance with IRC Section 41(d) which requires that qualifying activities:

(1) be technological in nature;
(2) meet a permitted purpose;
(3) include elements of technical uncertainty; and
(4) utilize a process of experimentation.

Each year Xcel Energy obtains a project listing by company, including jurisdiction, and holds meetings with individuals throughout the company to determine qualifying projects. Interviews are conducted to determine the portion of wages, supplies, and contract research associated with these projects that were related to qualifying R&E activities.

For the Minnesota R&E credit, the location of the project where the work was performed is used to determine the costs eligible for inclusion in the Minnesota credit. As noted above, only activities completed in Minnesota are allowable and utilized in calculation of the Minnesota R&E credit.

In order to forecast the amount included in the 2016 through 2020 Test Years for the Minnesota Electric Rate Case filing, we used an adjusted average of the three prior years of finalized Minnesota R&E credit claims. At the time of filing, the 2011 through 2013 calculations were the most recent years available. Attachment A to this response provides the calculation of the adjusted three-year average of Minnesota R&E credits used to forecast the Minnesota R&E credit for the 2016 through 2020 Test Years. The 2011 through 2013 Minnesota Tax Schedules RD are included as Attachment B to this response in support the three year average as calculated in Attachment A. These forms were filed with the respective year's Minnesota income tax return to claim the Research & Experimentation credit.

B. A Federal research & experimentation credit was not included in the original rate plans since, at the time of filing, the credit had expired as of December 31, 2014 and, therefore, no credit was allowed for the 2016 through 2020 Test Years.

On December 18, 2015 the Consolidated Appropriations Act, 2016 was signed into law permanently extending the Federal R&E credit. As a result, an adjustment to the rate plans will be made with rebuttal to include Federal R&E credit amounts for 2016 through 2020.

C. All Federal and State research and experimentation credits applicable at the time of the filing are included in our initial request. Please see Volume 4A, Test Year Workpapers Base Data, Section P8. Tax Credits or CD File Base RB P8 Tax Credits for detail on adjustments. Please see Attachment C to this response for the Federal R&E credit that will be submitted as a rebuttal adjustment.

Attachments A and B have been marked Non-Public, Attachment B in its entirety, as they contain information the Company considers to be trade secret data as defined by Minn. Stat. §13.37(1)(b). This information is considered Trade Secret because it contains financial information of a privileged nature, which if disclosed, could jeopardize the Company. Thus, Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500, subp 3. The information contained in Attachment B was prepared by Xcel Energy's corporate tax department in relation to filing its corporate tax returns for the tax periods noted therein. A copy was pulled by the Income Tax group for inclusion with this information request.

Witness:	Anne Heuer
Preparer:	Jennifer Langstraat / Shari Cardille
Title:	Consultant, Income Tax Compliance & Acctg / Principal Rate Analyst
Department:	Tax Services / Revenue Requirements North
Telephone:	612-330-6524 / 612-330-1974
Date:	March 29, 2016

PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED
— PUBLIC DATA —
TRADE SECRET DATA HAS BEEN SHADED

Northern States Power Company

Docket No. E002/GR-15-826
DOC Information Request No. 159
Attachment A - Page 1 of 1

2011, 2012 & 2013 Minnesota R&E Credit Average Used for Calculation of FTY 2016-2020

	2011	2012	2013	'11-'13 Average
Total MN R&E Credit Claimed on Schedule RD				
Adjustment for Increased Spend in 2013[1]				
Total MN R&E Credit used in 2016 FTY				
Total MN R&E Credit for 2016 FTY, Net Federal				
ROUNDED - Amount included in 2016 FTY				

The amount included in the 2016 through 2020 Test Years for the Minnesota Electric Rate Case filing for Minnesota R&E credit was based on an adjusted average of the prior three years of credit claimed, with 2011, 2012 and 2013 being the most recent years available at the time of filing.

[1] Due to extraordinary project spend in 2013 with large value, non-recurring projects, the 2013 credit amount which was used in in the average was adjusted.

NON-PUBLIC DOCUMENT IN ENTIRETY
CONTAINS TRADE SECRET INFORMATION AND NON-PUBLIC DATA

The tax schedules, referenced in the Company's response to DOC Information Request No. 159, are entitled: *2011, 2012 and 2013 Credit for Increasing Research Activities*. The schedules contain information prepared by Xcel Energy's corporate tax department in relation to filing its corporate tax returns for the tax periods noted therein and consists of 3 pages in total. Copies of the respective years were pulled by the Income Tax group for inclusion with this information request. These tax schedules contain information the Company considers to be trade secret data as defined by Minn. Stat. §13.37(1)(b) and because they contain sensitive business and financial information that the Company does not publically disclose, Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500, subp 3.

Annual Revenue Requirement
Federal Research and Experimentation Credit
2016-2018 MYRP plus 2019-2020 Fcst
(000's)

		Total Company					MN Jurisdiction				
	Rate Analysis	2016	2017	2018	2019	2020	2016	2017	2018	2019	2020
1	Average Balances:										
2	Plant Investment	-	-	-	-	-	-	-	-	-	-
3	Depreciation Reserve	-	-	-	-	-	-	-	-	-	-
4	CWIP	-	-	-	-	-	-	-	-	-	-
5	Accumulated Deferred Taxes	-	-	-	-	-	-	-	-	-	-
6	Average Rate Base = line 1 - line 3 + line 4 - line 5	-	-	-	-	-	-	-	-	-	-
7											
8	Revenues:										
9	Interchange Agreement offset	-	-	-	-	-	-	-	-	-	-
10											
11	Expenses:										
12	Book Depreciation	-	-	-	-	-	-	-	-	-	-
13	Annual Deferred Tax	-	-	-	-	-	-	-	-	-	-
14	ITC Flow Thru	-	-	-	-	-	-	-	-	-	-
15	Property Taxes	-	-	-	-	-	-	-	-	-	-
16	subtotal expense = lines 12 thru 15	-	-	-	-	-	-	-	-	-	-
17											
18	Tax Preference Items:										
19	Tax Depreciation & Removal Expense	-	-	-	-	-	-	-	-	-	-
20	Tax Credits (enter as negative)	(4,030)	(4,030)	(4,030)	(4,030)	(4,030)	(3,519)	(3,519)	(3,519)	(3,519)	(3,519)
21	Avoided Tax Interest	-	-	-	-	-	-	-	-	-	-
22											
23	AFUDC	-	-	-	-	-	-	-	-	-	-
24											
25	Returns:										
26	Debt Return = line 6 x (line 41 + line 42)	-	-	-	-	-	-	-	-	-	-
27	Equity Return = line 6 x (line 43 + line 44)	-	-	-	-	-	-	-	-	-	-
28											
29	Tax Calculations:										
30	Equity Return = line 27	-	-	-	-	-	-	-	-	-	-
31	Taxable Expenses = lines 12 thru 14	-	-	-	-	-	-	-	-	-	-
32	plus Tax Additions = line 21	-	-	-	-	-	-	-	-	-	-
33	less Tax Deductions = (line 19 + line 23)	-	-	-	-	-	-	-	-	-	-
34	subtotal	-	-	-	-	-	-	-	-	-	-
35	Tax gross-up factor = t / (1-t) from line 47	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611
36	Current Income Tax Requirement = line 34 x line 35	-	-	-	-	-	-	-	-	-	-
37	Tax Credit Revenue Requirement = line 20 x line 35 + line 20	(6,874)	(6,874)	(6,874)	(6,874)	(6,874)	(6,003)	(6,003)	(6,003)	(6,003)	(6,003)
38	Total Current Tax Revenue Requirement = line 36+ line 37	(6,874)	(6,874)	(6,874)	(6,874)	(6,874)	(6,003)	(6,003)	(6,003)	(6,003)	(6,003)
39											
40	Total Revenue Requirements	(6,874)	(6,874)	(6,874)	(6,874)	(6,874)	(6,003)	(6,003)	(6,003)	(6,003)	(6,003)
41	= line 16 + line 26 + line 27 + line 38 - line 23 + line 9										
42	O&M Expense	-	-	-	-	-	-	-	-	-	-
43	Total Revenue Requirements	(6,874)	(6,874)	(6,874)	(6,874)	(6,874)	(6,003)	(6,003)	(6,003)	(6,003)	(6,003)

	Capital Structure	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**
41	**Long Term Debt**	**2.2200%**	**2.2100%**	**2.2100%**	**2.1800%**	**2.2000%**
42	**Short Term Debt**	**0.0200%**	**0.0500%**	**0.0500%**	**0.0700%**	**0.0800%**
43	**Preferred Stock**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
44	**Common Equity**	**5.2500%**	**5.2500%**	**5.2500%**	**5.2500%**	**5.2500%**
45	**Required Rate of Return**	**7.4900%**	**7.5100%**	**7.5100%**	**7.5000%**	**7.5300%**
46	**PT Rate**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
47	**Tax Rate (MN)**	**41.3700%**	**41.3700%**	**41.3700%**	**41.3700%**	**41.3700%**
48	**MN JUR Energy**	**87.3278%**	**87.3278%**	**87.3278%**	**87.3278%**	**87.3278%**
49	**MN JUR Demand**	**87.3461%**	**87.3461%**	**87.3461%**	**87.3461%**	**87.3461%**
50	**IA Demand**	**84.1349%**	**84.1349%**	**84.1349%**	**84.1349%**	**84.1349%**

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-15-826		
Response To:	MN Department of Commerce	Information Request No.	2125
Requestor:	Nancy Campbell, Dale Lusti, Angela Byrne		
Date Received:	May 18, 2016		**REVISED**

Question:

Reference: Response to DOC IR 159 – Attachments A and C

Subject: State and Federal Research and Experimentation Tax Credits

A. Please update the State Research and Experimentation tax credits on Attachment A with 2014 and 2015 actual tax amounts, or explain why these tax amounts are not available.

B. Please provide tax information and calculations supporting the Federal Research and Experimentation tax credits shown on Attachment C.

Response:

A. NSPM's 2014 Minnesota R&E credit was **[BEGIN TRADE SECRET… …END TRADE SECRET]**. Please refer to Attachment A to this response for a copy of NSPM's Schedule RD included in the 2014 Corporation Franchise Tax Return for Xcel Energy Inc. and Affiliates. Please refer to Attachment B to this response for an update to Attachment A to Information Request No. DOC-159. The updated 3-year average, including 2014 actuals, would be $492,000.

The 2015 Minnesota state income tax return, including the 2015 Minnesota Schedule RD, is not yet available; it will be filed in September 2016.

B. The $4,030,000 of R&E included in the Annual Revenue Requirement for each of 2016-2020 was forecasted based on a 3-year average of 2012-2014 R&E credits:

Federal R&E Credit Forecast for 2016-2020				
	2012	**2013**	**2014**	**Average**
	[BEGIN TRADE SECRET	[BEGIN TRADE SECRET	[BEGIN TRADE SECRET	
Federal R&E Credit Claimed				$4,030,168
	END TRADE SECRET]	END TRADE SECRET]	END TRADE SECRET]	

Please refer to NSPM's Form 6765s, Credit for Increasing Research Activities, included in each year's U.S. Corporation Income Tax Return for Xcel Energy Inc. and Affiliates for calculations supporting each year's federal Research and Experimentation tax credits:

Attachment C 2012 Form 6765
Attachment D 2013 Form 6765
Attachment E 2014 Form 6765

Consistent with prior treatment of the Company's income tax returns and tax information, Portions of this response and Attachments A, B, C, D and E to this response have been marked Non-Public as they contain information the Company considers to be trade secret data as defined by Minn. Stat. §13.37(1)(b). The information derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons who could obtain economic value and/or a competitive advantage from its disclosure or use. Thus, Xcel Energy maintains this information as a trade secret.

Attachments A, C, D and E provided with the non-public version of this response have been marked "Trade Secret" in their entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material**: Attachments A, C, D and E include copies of NSPM's Schedule RD included in the 2014 Corporation Franchise Tax Return for Xcel Energy Inc. and Affiliates (Att. A - 1 page); and NSPM's Form 6765 Credit for Increasing Research Activities, included in years 2012 through 2014 U.S. Corporation Income Tax Return for Xcel Energy Inc. and Affiliates (Atts. C, D & E - 2 pages each).
2. **Authors**: The form was prepared by Xcel Energy's corporate tax department.

3. **Importance**: The form includes corporate financial information that Xcel Energy maintains as trade secret.
4. **Date the Information was Prepared**: The information was prepared between 2013 and 2015 for filing with the Internal Revenue Service.

Preparer:	Leah Lovley
Title:	Senior Income Tax Analyst
Department:	Tax Services
Telephone:	612-321-3243
Date:	May 26, 2016

Revised: May 31, 2016

PUBLIC DOCUMENT
TRADE SECRET INFORMATION AND NON-PUBLIC DATA EXCISED

Attachments A, C, D and E provided with the non-public version of this response have been marked "Trade Secret" in their entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material**: Attachments A, C, D and E include copies of NSPM's Schedule RD included in the 2014 Corporation Franchise Tax Return for Xcel Energy Inc. and Affiliates (Att. A - 1 page); and NSPM's Form 6765 Credit for Increasing Research Activities, included in years 2012 through 2014 U.S. Corporation Income Tax Return for Xcel Energy Inc. and Affiliates (Atts. C, D & E - 2 pages each).

2. **Authors**: The form was prepared by Xcel Energy's corporate tax department.

3. **Importance**: The form includes corporate financial information that Xcel Energy maintains as trade secret.

4. **Date the Information was Prepared**: The information was prepared between 2013 and 2015 for filing with the Internal Revenue Service.

Northern States Power Company

Docket No. E002/GR-15-826
DOC Information Request No. 2125
Attachment B-REVISED - Page 1 of 1

2012, 2013 & 2014 Minnesota R&E Credit Average

	2012	**2013**	**2014**	**'12-'14 Average**
Total MN R&E Credit Claimed on Schedule RD				828,290
Adjustment for Increased Spend in 2013[1]				
Total MN R&E Credit used in 2016 FTY				756,837
Total MN R&E Credit for 2016 FTY, Net Federal				491,944
ROUNDED				**492,000**

[1] Due to extraordinary project spend in 2013 with large value, non-recurring projects, the 2013 credit amount which was used in the average was adjusted.

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

Xcel Energy			
Docket No.:	E002/GR-15-826		
Response To:	MN Department of Commerce	Information Request No.	188
Requestor:	Nancy Campbell, Angela Byrne, Dale Lusti		
Date Received:	April 5, 2016		

Question:

Reference: Vol. 3 Required Information, II Required Financial Information, C-1 & C-5

a) On C-1 Operating Income Schedules, please explain why the Company uses 35% for federal income taxes rate, instead of 31.57% (federal income taxes rate of 35% less state benefit of 3.43%) shown on C-5?

b) What income tax rates does the Company use for Rate Base Schedules for the 2016 to 2020 test years (including both 3-year and 5-year rate plans)? Please explain and support your response.

c) What income tax rates does the Company use for Income Statement Schedules for the 2016 to 2020 test years (including both 3-year and 5-year rate plans)? Please explain and support your response.

d) Has the Company changed its income taxes rates or method to calculate for use in its financial schedules and test years in this rate case, compared to what has been used in the past two rate cases? Please support your response.

e) On C-5, the Company shows a Composite rate for MN, ND, SD and Federal Income Taxes of 40.81%. What does the Company use this 40.81% composite tax rate for purposes of the 2016 to 2020 test years (including both 3-year and 5-year rate plans)? Please explain and support your response.

Response:

a. Rather than using a blended tax rate to calculate Federal income taxes, the Company uses the Minnesota state statutory tax rate to calculate Minnesota state taxes and then uses the resulting state taxes as a deduction in calculating Federal Taxable Income, to which the Federal statutory tax rate is applied. This method of calculating Federal income taxes results in the blended Federal income tax rate of 31.57%. As shown on Schedule C-1, State income taxes are calculated using the Minnesota statutory tax rate of 9.80%, while Federal income taxes are calculated using the 35% statutory income tax rate. The Federal income tax deduction associated with the state income taxes can be found on line 27. The state income taxes shown on line 27 will be a deduction in determining the Federal Taxable income amount shown on line 29 and in effect has the same impact as using a blended tax rate of 31.57% shown on Schedule C-5.

b. The only component of rate base that is impacted by tax rates on the Rate Base Schedules is Accumulated Deferred Income Taxes (ADIT). In the 2016 Test Year and the 2017 and 2018 Plan Years, the Annual Deferred Tax Expense was calculated using a Corporate Composite Tax Rate of 40.8097% shown in Vol. 4A Test Year Workpapers Base Data, V. O&M, 05. State & Federal Income Taxes. For further discussion of how the mechanics of the five-year offer will operate, please see the Company's response to DOC Information Request No. 133.

For plant related ADIT, the annual deferred taxes are maintained by vintage, and each vintage sets up at the current Corporate Composite income tax rate and under the average rate assumption method (ARAM) flows back at the average of all the current rates used to set up the deferred income taxes. The set-up occurs for all years where the tax depreciation (and deductions) is greater than the book depreciation and flows back when the reverse occurs. Using ARAM assures that as annual composite income tax rates change, the overall deferred liability is not immediately adjusted upward or downward, which would change the rate base offset of the deferred liability in the current period due to the changing income tax rates. ARAM allows the deferred income taxes to flow back at the average of the tax rates used to set it up.

For non-plant, both the Annual Deferred Income Tax Expense and the ADIT use the Corporate Composite income tax rate of 40.8097% in the 2016 Test Year and the 2017 and 2018 Plan Years. In addition, the Company records an annual income tax rate true-up to reflect the latest forecasted income tax rate. This true-up is recorded to Deferred Income Tax Expense.

c. As discussed in part a. above, the Company uses the statutory Minnesota and Federal tax rates to calculate current income tax expense on the Income Statement Schedules As discussed in part b. above, the Company uses the Corporate Composite tax rate to calculate Annual Deferred Income Tax Expense on the Income Statement Schedules. Please see Vol. 4A Test Year Workpapers Base Data, V. O&M, 05. State & Federal Income Taxes for the Income tax rates used in the calculation of current and deferred income taxes for the duration of the 2016 test year and the 2017 and 2018 plan years. For further discussion of how the mechanics of the five-year offer will operate, please see the response to DOC IR 133.

d. The Company's method in calculating income tax rates has remained consistent in this rate case in comparison to prior cases. However, when comparing the tax rates used in the financial schedules and test years in this rate case to prior cases, slight changes will be shown as a result of changes in state statutory income tax rates and state income apportionment factors. Please see Attachment A to this response for support of the income tax rates used in the current rate case along with the income tax rates used over the past two cases.

e. Please see parts b. and c. above, for an explanation of the use of the Corporate Composite income tax rate in the 2016 Test Year and the 2017 and 2018 Plan Years. Our five-year forecast is produced under the same methodology.

We note that the Company's request in this rate case is that presented as our three-year plan, based on our forecasted capital expenditures and indexed O&M costs through a cost of service model. We also provided our five-year offer which is just that, an offer of settlement. While our long-term forecasts informed this settlement offer, it was not determined based on traditional cost of service ratemaking. Rather, we have offered a "rate shape" that we believe appropriately balances the certainty provided by a five-year outcome and sufficient revenue to provide safe and reliable service over the five-year period. This rate shape settlement offer is "discounted" against outcomes of traditional cost of service ratemaking to incentivize settlement discussions. We have provided our five-year budgets and forecasts in this case to provide a comparison point for our five-year offer. Please see Mr. Company witness Mr. Aakash H. Chandarana's Direct Testimony, pages 73-79 and the Company's response to Information Request No. DOC-133 in this docket for additional information regarding the five-year settlement offer.

Witness:	Anne E. Heuer / Lisa H. Perkett
Preparer:	Nate Schraan
Title:	Rate Analyst
Department:	Revenue Analysis
Telephone:	612-330-7661
Date:	April 15, 2016

NORTHERN STATES POWER COMPANY, MINNESOTA
STATUTORY TAX RATE CALCULATION
FORECASTED 2013 TAX RATE
BASED UPON 2011 INCOME TAX RETURNS

STATE	APPORTIONMENT FACTOR	STATE TAX RATE	APPORTIONED TAX RATE (COL.B x COL.C)	FED RATE	STATE BENEFIT (COL D x COL.E]	NET FEDERAL RATE (COL.E - COL.F - COL.G)	ROUNDING	STATUTORY RATE (COLUMNS D,H,I)
COLUMN A	*COLUMN B*	*COLUMN C*	*COLUMN D*	*COLUMN E*	*COLUMN F*	*COLUMN H*	*COLUMN I*	*COLUMN J*
JURISDICTIONAL								
GEORGIA	100.0000%	6.0000%	6.0000%	35.0000%	2.1000%	32.9000%	0.0000%	38.9000%
MINNESOTA	100.0000%	9.8000%	9.8000%	35.0000%	3.4300%	31.5700%	0.0000%	41.3700%
NORTH DAKOTA	100.0000%	5.1500%	5.1500%	35.0000%	1.8025%	33.1975%	0.0000%	38.3475%
SOUTH DAKOTA	100.0000%	0.0000%	0.0000%	35.0000%	0.0000%	35.0000%	0.0000%	35.0000%
COMPOSITE								
GEORGIA	0.0000%	6.0000%	**0.0000%**	35.0000%	0.0000%	0.0000%		0.0000%
MINNESOTA	90.8395%	9.8000%	**8.9023%**	35.0000%	3.1158%	-3.1158%		5.7865%
NORTH DAKOTA	3.1710%	5.1500%	**0.1633%**	35.0000%	0.0572%	-0.0572%		0.1061%
SOUTH DAKOTA	0.0000%	0.0000%	**0.0000%**	35.0000%	0.0000%	0.0000%		0.0000%
STATE SUBTOTAL	94.0105%		9.0656%	35.0000%	3.1730%	-3.1730%		5.8926%
FEDERAL	0.0000%	0.0000%	0.0000%	35.0000%	0.0000%	35.0000%		35.0000%
ROUNDING						0.0000%		0.0000%
TOTAL COMPOSITE RATE	94.0105%		9.0656%	35.0000%	3.1730%	**31.8270%**		**40.8926%**

COMPOSITE TAX RATE RECAP

GEORGIA	**0.0000%**
MINNESOTA	**8.9023%**
NORTH DAKOTA	**0.1633%**
SOUTH DAKOTA	**0.0000%**
FEDERAL	**31.8270%**
TOTAL	**40.8926%**

Northern States Power Company, a Minnesota corporation
Electric Operations - State of Minnesota
OPERATING INCOME SCHEDULES
DEVELOPMENT OF FEDERAL AND STATE INCOME TAX RATES
Most Recent Fiscal Year 2011
Proposed Test Year 2013
Unadjusted Test Year 2013

Docket No. E002/GR-12-961
Financial Information
Schedule C-5

Let: F=Federal Income Tax = 35.00%
M=Minnesota State Income Tax Rate = 9.80%
D=North Dakota State Income Tax Rate = 5.15%
S=South Dakota State Income Tax Rate = 0%
N=Net Income After Interest Deductions but Before Income Taxes

Jurisdictional:

Only Minnesota and Federal Income Taxes

M=	9.80%	(N)
F=	31.57%	(N)
M+F=	41.37%	(N)

Only North Dakota and Federal Income Taxes

D=	5.15%	(N)
F=	33.20%	(N)
D+F=	38.35%	(N)

Only South Dakota and Federal Income Taxes

S=	0.00%	(N)
F=	35.00%	(N)
S+F=	35.00%	(N)

Composite:

Northern States Power Company (Minnesota): Combined Minnesota, North Dakota, South Dakota and Federal Income Taxes:

M + D + S + F = 40.89% (N)

Notes:
1. Investment tax credits and surtax credits are ignored.
2. State income taxes are deductible from federal taxable income. Federal income tax is deductible only from North Dakota's taxable income.
3. Net income is defined at each jurisdictional level.
4. Composite income tax rates are determined by the Income Tax Department based upon apportionment laws (unitary and nonunitary) for each state involved.

NORTHERN STATES POWER COMPANY, MINNESOTA
STATUTORY TAX RATE CALCULATION
FORECASTED 2014 TAX RATE
BASED UPON 2012 INCOME TAX RETURNS

STATE	APPORTIONMENT FACTOR	STATE TAX RATE	APPORTIONED TAX RATE (COL B x COL C)	FED RATE	STATE BENEFIT (COL D x COL E)	NET FEDERAL RATE (COL E - COL F)	ROUNDING	STATUTORY RATE (COL D + G + H)
COLUMN A	*COLUMN B*	*COLUMN C*	*COLUMN D*	*COLUMN E*	*COLUMN F*	*COLUMN G*	*COLUMN H*	*COLUMN I*
JURISDICTIONAL								
CALIFORNIA	100.0000%	8.8400%	8.8400%	35.0000%	3.0940%	31.9060%	0.0000%	40.7460%
GEORGIA	100.0000%	6.0000%	6.0000%	35.0000%	2.1000%	32.9000%	0.0000%	38.9000%
MINNESOTA	100.0000%	9.8000%	9.8000%	35.0000%	3.4300%	31.5700%	0.0000%	41.3700%
NORTH DAKOTA	100.0000%	4.5300%	4.5300%	35.0000%	1.5855%	33.4145%	0.0000%	37.9445%
SOUTH DAKOTA	100.0000%	0.0000%	0.0000%	35.0000%	0.0000%	35.0000%	0.0000%	35.0000%
COMPOSITE								
CALIFORNIA	0.0000%	8.8400%	**0.0000%**	35.0000%	0.0000%	0.0000%		0.0000%
GEORGIA	0.0000%	6.0000%	**0.0000%**	35.0000%	0.0000%	0.0000%		0.0000%
MINNESOTA	90.4641%	9.8000%	**8.8655%**	35.0000%	3.1029%	-3.1029%		5.7626%
NORTH DAKOTA	3.1342%	4.5300%	**0.1420%**	35.0000%	0.0497%	-0.0497%		0.0923%
SOUTH DAKOTA	0.0000%	0.0000%	**0.0000%**	35.0000%	0.0000%	0.0000%		0.0000%
STATE SUBTOTAL	93.5983%		9.0075%	35.0000%	3.1526%	-3.1526%		5.8549%
FEDERAL	0.0000%	0.0000%	0.0000%	35.0000%	0.0000%	35.0000%		35.0000%
ROUNDING						0.0000%		0.0000%
TOTAL COMPOSITE RATE	93.5983%		9.0075%	35.0000%	3.1526%	**31.8474%**		**40.8549%**

COMPOSITE TAX RATE RECAP

CALIFORNIA	**0.0000%**
GEORGIA	**0.0000%**
MINNESOTA	**8.8655%**
NORTH DAKOTA	**0.1420%**
SOUTH DAKOTA	**0.0000%**
FEDERAL	**31.8474%**
TOTAL	**40.8549%**

Northern States Power Company
Electric Operations - State of Minnesota
OPERATING INCOME SCHEDULES
DEVELOPMENT OF FEDERAL AND STATE INCOME TAX RATES
Most Recent Fiscal Year 2012
Proposed Test Year 2014
Unadjusted Test Year 2014

Docket No. E002/GR-13-868
Financial Information
Schedule C-5

Let: F=Federal Income Tax = 35.00%
M=Minnesota State Income Tax Rate = 9.80%
D=North Dakota State Income Tax Rate = 4.53%
S=South Dakota State Income Tax Rate = 0%
N=Net Income After Interest Deductions but Before Income Taxes

Jurisdictional:

Only Minnesota and Federal Income Taxes

M=	9.80%	(N)
F=	31.57%	(N)
M+F=	41.37%	(N)

Only North Dakota and Federal Income Taxes

D=	4.53%	(N)
F=	33.41%	(N)
D+F=	37.94%	(N)

Only South Dakota and Federal Income Taxes

S=	0.00%	(N)
F=	35.00%	(N)
S+F=	35.00%	(N)

Composite:

Northern States Power Company (Minnesota): Combined Minnesota, North Dakota, South Dakota and Federal Income Taxes:

M + D + S + F = 40.85% (N)

Notes:
1. Investment tax credits and surtax credits are ignored.
2. State income taxes are deductible from federal taxable income. Federal income tax is deductible only from North Dakota's taxable income.
3. Net income is defined at each jurisdictional level.
4. Composite income tax rates are determined by the Income Tax Department based upon apportionment laws (unitary and nonunitary) for each state involved.

NORTHERN STATES POWER COMPANY, MINNESOTA
STATUTORY TAX RATE CALCULATION
FORECASTED 2014 TAX RATE
BASED UPON 2013 INCOME TAX RETURNS

*****In April, North Dakota passed legislation decreasing its corporate income tax rate, effective 1/1/2015. Tax services will book the rate change in Q3.**

STATE	APPORTIONMENT FACTOR	STATE TAX RATE	APPORTIONED TAX RATE (COL B x COL C)	FED RATE	STATE BENEFIT (COL D x COL E)	NET FEDERAL RATE (COL E - COL F)	ROUNDING	STATUTORY RATE (COL D + G + H)
COLUMN A	*COLUMN B*	*COLUMN C*	*COLUMN D*	*COLUMN E*	*COLUMN F*	*COLUMN G*	*COLUMN H*	*COLUMN I*
JURISDICTIONAL								
CALIFORNIA	100.0000%	8.8400%	8.8400%	35.0000%	3.0940%	31.9060%	0.0000%	40.7460%
COLORADO	100.0000%	4.6300%	4.6300%	35.0000%	1.6205%	33.3795%	0.0000%	38.0095%
GEORGIA	100.0000%	6.0000%	6.0000%	35.0000%	2.1000%	32.9000%	0.0000%	38.9000%
MINNESOTA	100.0000%	9.8000%	9.8000%	35.0000%	3.4300%	31.5700%	0.0000%	41.3700%
NORTH DAKOTA	100.0000%	4.3100%	4.3100%	35.0000%	1.5085%	33.4915%	0.0000%	37.8015%
SOUTH DAKOTA	100.0000%	0.0000%	0.0000%	35.0000%	0.0000%	35.0000%	0.0000%	35.0000%
WISCONSIN	100.0000%	7.9000%	7.9000%	35.0000%	2.7650%	32.2350%	0.0000%	40.1350%
COMPOSITE								
CALIFORNIA	0.0000%	8.8400%	**0.0000%**	35.0000%	0.0000%	0.0000%		0.0000%
COLORADO	0.0000%	4.6300%	**0.0000%**	35.0000%	0.0000%	0.0000%		0.0000%
GEORGIA	0.0000%	6.0000%	**0.0000%**	35.0000%	0.0000%	0.0000%		0.0000%
MINNESOTA	89.7764%	9.8000%	**8.7981%**	35.0000%	3.0793%	-3.0793%		5.7188%
NORTH DAKOTA	3.2465%	4.3100%	**0.1399%**	35.0000%	0.0490%	-0.0490%		0.0909%
SOUTH DAKOTA	0.0000%	0.0000%	**0.0000%**	35.0000%	0.0000%	0.0000%		0.0000%
WISCONSIN	0.0000%	7.9000%	**0.0000%**	35.0000%	0.0000%	0.0000%		0.0000%
STATE SUBTOTAL	93.0229%		8.9380%	35.0000%	3.1283%	-3.1283%		5.8097%
FEDERAL	0.0000%	0.0000%	0.0000%	35.0000%	0.0000%	35.0000%		35.0000%
ROUNDING						0.0000%		0.0000%
TOTAL COMPOSITE RATE	93.0229%		8.9380%	35.0000%	3.1283%	**31.8717%**		**40.8097%**

COMPOSITE TAX RATE RECAP

CALIFORNIA	**0.0000%**
COLORADO	**0.0000%**
GEORGIA	**0.0000%**
MINNESOTA	**8.7981%**
NORTH DAKOTA	**0.1399%**
SOUTH DAKOTA	**0.0000%**
WISCONSIN	**0.0000%**
FEDERAL	**31.8717%**
TOTAL	**40.8097%**

Northern States Power Company
Electric Operations - State of Minnesota
OPERATING INCOME SCHEDULES
DEVELOPMENT OF FEDERAL AND STATE INCOME TAX RATES
Most Recent Fiscal Year 2014
Proposed Test Year 2016
Unadjusted Test Year 2016

Docket No. E002/GR-15-826
Financial Information
Schedule C-5

Let: F=Federal Income Tax = 35.00%
M=Minnesota State Income Tax Rate = 9.80%
D=North Dakota State Income Tax Rate = 4.31%
S=South Dakota State Income Tax Rate = 0%
N=Net Income After Interest Deductions but Before Income Taxes

Jurisdictional:

Only Minnesota and Federal Income Taxes

M=	9.80%	(N)
F=	31.57%	(N)
M+F=	41.37%	(N)

Only North Dakota and Federal Income Taxes

D=	4.31%	(N)
F=	33.49%	(N)
D+F=	37.80%	(N)

Only South Dakota and Federal Income Taxes

S=	0.00%	(N)
F=	35.00%	(N)
S+F=	35.00%	(N)

Composite:

Northern States Power Company (Minnesota): Combined Minnesota, North Dakota, South Dakota and Federal Income Taxes:

M + D + S + F = 40.81% (N)

Notes:
1. Investment tax credits and surtax credits are ignored.
2. State income taxes are deductible from federal taxable income. Federal income tax is deductible only from North Dakota's taxable income.
3. Net income is defined at each jurisdictional level.
4. Composite income tax rates are determined by the Income Tax Department based upon apportionment laws (unitary and nonunitary) for each state involved.

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

Xcel Energy			
Docket No.:	E002/GR-15-826		
Response To:	MN Department of Commerce	Information Request No.	1141
Requestor:	Nancy Campbell, Dale Lusti, Angela Byrne		
Date Received:	April 22, 2016		

Question:

Reference: N/A

Subject: North Dakota Taxes

a) Please identify all North Dakota Taxes (include all expenses, revenues, credits, etc.) by tax type included in the test year (include total company and Minnesota Jurisdictional amounts, with support for Minnesota Jurisdictional allocator).

b) Please identify all North Dakota Taxes (include all expenses, revenues, credits, etc.) by tax type not included in the test year (include total company and Minnesota Jurisdictional amounts, with support for Minnesota Jurisdictional allocator).

c) Please justify why it is reasonable that some North Dakota Taxes are included in the test year (question a) and why some North Dakota Taxes are not included in the test year (question b).

Response:

a) and b)

The table below shows North Dakota taxes both included in and excluded from 2016 Test Year Cost of Service Study (COSS). For each tax type, we indicate: 1) whether the cost is included in the Test Year; 2) allocated, direct assigned, or calculated within the COSS; 3) the cost causative basis used for allocation, assignment, or calculation; and 4) the rational used for such treatment.

	Included In MN COSS	Method	Cost Causative Allocation or Assignment Basis	Rational for Cost Causative Basis
System Related Shared Taxes ND Taxes/Tax Credits Included In Test Year				
ND Property Tax	Yes	Allocated	Production & Transmission Plant Investment	Tax based on Production & Transmission Property
ND Payroll Tax	Yes	Allocated	Labor-related	Follows the assignment or allocation of labor
ND Sales Tax	Yes	Allocated	Recorded with O&M or Capital cost	Follows the assignment or allocation of underlying cost
ND Deferred Income Tax	Yes	Allocated	Underlying Investment in Plant & Other Rate Base	Follows the assignment of Production & Transmission Property or Nature of Other Rate Base Item
Current Income Taxes and Related Credits ND Taxes/Tax Credits NOT Included In Test Year				
ND Current Income Tax	No	COSS Calculation	Tax Rates Based on ND State Law	Stand-Alone COSS tax methodology based on ND Taxable Income, net of Tax Credits
ND Investment Tax Credit	No	Direct ND	ND State Tax Law	Credit to ND Current Income Tax

Attachment A to this response provides revenue requirements by tax type included in the Minnesota COSS for the 2016 Test Year and the 2017 and 2018 Plan Years. Additional discussion of Attachment A is provided in response to part c) below.

c) As a general description of the information as shown in the table above, there are two categories of tax types:

- *System Related Shared Taxes.* Taxes that are related the Company's ownership and operation of the integrated generation and transmission system are allocated among jurisdictions. This cost sharing is consistently applied without regard to the physical location of the generation or transmission asset.

- *Current Income Taxes.* Current State and Federal income taxes, and credits intended to offset income taxes, are state specific. Current income taxes and any associated credits are not shared among jurisdictions; rather, the calculation of income taxes is an integral part of the mechanics of the individual cost of service studies for each state.

We discuss these tax types and COSS treatment in further detail below.
We note that while this question and our response refers specifically to North Dakota taxes, the treatment of taxes is the same regardless of whether the taxes are related to Minnesota, North Dakota, or South Dakota.

System Related Shared Taxes

As described in Company witness Ms. Anne Heuer's Direct Testimony, NSP-Minnesota and NSP-Wisconsin together own and operate the integrated generation and transmission system (NSP System). The costs of the overall system are shared between the two companies through the FERC-regulated Interchange Agreement. Then, in turn, NSPM's portion of the NSP System costs are allocated amongst the NSPM retail jurisdictions (Minnesota, North Dakota and South Dakota). As discussed in the Direct Testimony of Company witness Mr. Adam Dietenberger, some costs are direct assigned and some costs are allocated based on cost causative relationships between the nature of the cost and the customers who benefit from the cost. Costs incurred directly in support of customers in one state are direct assigned. Costs that benefit more than one jurisdiction are allocated. As a result, the overall revenue requirement determined by the COSS includes, among other costs and revenues, both direct and indirect costs and revenues in support of the NSP System. This cost sharing is consistently applied without regard to the physical location of the generation or transmission asset.

As illustrated in the table above, North Dakota Property Taxes, North Dakota Payroll Taxes, North Dakota Sales Taxes, and North Dakota Deferred Taxes that are either directly or indirectly associated with the NSP System are allocated to the Minnesota jurisdiction based on cost causation.

Current Income Taxes and Related Credits

As noted above, current State and Federal income taxes are not shared costs. Current income taxes are calculated as a part of the COSS for each state individually, where the applicable State and Federal tax rates are applied to the jurisdictional taxable income for that state. As such, State of North Dakota current income taxes and the North Dakota Investment Tax Credit, which is an offset to current North Dakota income taxes, are not assigned or allocated to Minnesota. Please see our response to Information Request DOC-1140 for additional discussion of the North Dakota Investment Tax Credit.

Attachment A

As mentioned above, Attachment A to this response provides revenue requirements by tax type included in the Minnesota COSS. Consistent with the treatment of taxes described above, the NSPM total Company amounts shown for the system related shared taxes (Property Tax, Payroll Tax, Sales Tax, and Deferred Income Tax) include the North Dakota taxes, along with Minnesota and South Dakota taxes. The NSPM amounts have been allocated to the Minnesota, North Dakota, and South Dakota jurisdictions according to cost causation.

Because Attachment A represents the Minnesota COSS, neither North Dakota nor South Dakota income taxes shown on Attachment A are representative of those states' calculated income taxes. Instead, the Minnesota COSS reflects the Minnesota tax rate of 9.8% applied to Minnesota's taxable income. (Please note that the North Dakota and South Dakota information is presented based on the Minnesota COSS logic and assumptions and does not represent tax determinations as are calculated in their respective stand-alone jurisdictional COSS.) Also consistent with the discussion above, Attachment A shows that the Minnesota state tax credits are direct assigned to Minnesota, fully benefiting Minnesota customers, with no portion reducing either North or South Dakota state taxes.

Witness:	Charles R. Burdick
Preparer:	Nate Schraan
Title:	Rate Analyst
Department:	Revenue Analysis
Telephone:	612-330-7661
Date:	May 14, 2016

NSPM - 00 Complete Revenue Requirements by Jurisdiction, 5yrs	Dec - 2016			
	Total	NSPM MN Electric Retail	NSPM ND Electric Retail	NSPM SD Electric Retail
Taxes:				
Property Taxes	210,192,485	186,751,259	11,294,419	12,146,807
ITC Amortization	(1,485,889)	(1,340,416)	(71,398)	(74,075)
Deferred Taxes	115,529,022	98,922,346	7,089,821	9,516,855
Deferred Taxes - NOL	143,535,226	120,693,096	10,989,927	11,852,203
Less Deferred State Tax Credits	558,701	558,701		
Less Deferred Federal Tax Credits	(38,093,994)	(31,842,924)	(3,235,834)	(3,015,235)
Deferred Income Tax & ITC	220,043,066	186,990,803	14,772,516	18,279,748
Payroll & Other Taxes	31,616,215	27,550,369	2,013,337	2,052,509
Total Taxes Other Than Income	**461,851,767**	**401,292,432**	**28,080,271**	**32,479,064**
State Taxes				
State Taxable Income	(159,799,530)	(145,979,635)	(12,476,556)	(1,343,339)
State Income Tax Rate	9.80%	9.80%	9.80%	9.80%
State Taxes before Credits	(15,660,354)	(14,306,004)	(1,222,702)	(131,647)
Less State Tax Credits	(559,000)	(559,000)		
Deferred State Tax Credits due to NOL	(558,701)	(558,701)	0	0
Total State Income Taxes	(16,778,055)	(15,423,705)	(1,222,702)	(131,647)
Federal Taxes				
Federal Sec 199 Production Deduction	3,425,905	3,425,905		
Federal Taxable Income	(146,447,380)	(133,981,834)	(11,253,854)	(1,211,692)
Federal Income Tax Rate	35.00%	35.00%	35.00%	35.00%
Federal Tax before Credits	(51,256,583)	(46,893,642)	(3,938,849)	(424,092)
Less Federal Tax Credits	(49,303,434)	(43,052,365)	(3,235,834)	(3,015,235)
Deferred Federal Tax Credits due to NOL	38,093,994	31,842,924	3,235,834	3,015,235
Total Federal Income Taxes	(62,466,024)	(58,103,083)	(3,938,849)	(424,092)
Total Taxes				
Total Taxes Other than Income	461,851,767	401,292,432	28,080,271	32,479,064
Total Federal and State Income Taxes	(79,244,078)	(73,526,788)	(5,161,551)	(555,739)
Total Taxes	382,607,688	327,765,644	22,918,720	31,923,324

Data Vintage: 2016 rate case budget

NSPM - 00 Complete Revenue Requirements by Jurisdiction, 5yrs	Dec - 2017			
	Total	NSPM MN Electric Retail	NSPM ND Electric Retail	NSPM SD Electric Retail
Taxes:				
Property Taxes	219,745,695	195,116,324	11,877,578	12,751,792
ITC Amortization	(1,485,889)	(1,340,416)	(71,398)	(74,075)
Deferred Taxes	81,818,498	67,049,745	6,489,604	8,279,149
Deferred Taxes - NOL	15,988,914		3,142,814	12,846,100
Less Deferred State Tax Credits				
Less Deferred Federal Tax Credits	49,966,663	52,991,330	970,524	(3,995,191)
Deferred Income Tax & ITC	146,288,186	118,700,659	10,531,544	17,055,983
Payroll & Other Taxes	32,405,127	28,238,438	2,062,286	2,104,403
Total Taxes Other Than Income	**398,439,007**	**342,055,421**	**24,471,408**	**31,912,178**
State Taxes				
State Taxable Income	142,544,939	143,372,042	4,174,173	(5,001,276)
State Income Tax Rate	9.80%	9.80%	9.80%	9.80%
State Taxes before Credits	13,969,404	14,050,460	409,069	(490,125)
Less State Tax Credits	(559,000)	(559,000)		
Deferred State Tax Credits due to NOL	0	0	0	0
Total State Income Taxes	13,410,404	13,491,460	409,069	(490,125)
Federal Taxes				
Federal Sec 199 Production Deduction	33,100,394	31,435,296	1,665,098	
Federal Taxable Income	96,034,141	98,445,286	2,100,006	(4,511,151)
Federal Income Tax Rate	35.00%	35.00%	35.00%	35.00%
Federal Tax before Credits	33,611,949	34,455,850	735,002	(1,578,903)
Less Federal Tax Credits	(54,752,676)	(46,470,000)	(4,287,486)	(3,995,191)
Deferred Federal Tax Credits due to NOL	(49,966,663)	(52,991,330)	(970,524)	3,995,191
Total Federal Income Taxes	(71,107,390)	(65,005,479)	(4,523,008)	(1,578,903)
Total Taxes				
Total Taxes Other than Income	398,439,007	342,055,421	24,471,408	31,912,178
Total Federal and State Income Taxes	(57,696,986)	(51,514,019)	(4,113,939)	(2,069,028)
Total Taxes	340,742,021	290,541,402	20,357,469	29,843,150

NSPM - 00 Complete Revenue Requirements by Jurisdiction, 5yrs	Dec - 2018			
	Total	NSPM MN Electric Retail	NSPM ND Electric Retail	NSPM SD Electric Retail
Taxes:				
Property Taxes	225,901,350	200,620,676	12,197,250	13,083,423
ITC Amortization	(1,485,889)	(1,340,416)	(71,398)	(74,075)
Deferred Taxes	78,585,524	64,884,087	6,129,787	7,571,650
Deferred Taxes - NOL	4,652,557			4,652,557
Less Deferred State Tax Credits				
Less Deferred Federal Tax Credits	67,488,884	62,148,736	3,398,745	1,941,403
Deferred Income Tax & ITC	149,241,076	125,692,407	9,457,133	14,091,536
Payroll & Other Taxes	33,007,515	28,762,959	2,101,067	2,143,489
Total Taxes Other Than Income	**408,149,941**	**355,076,042**	**23,755,450**	**29,318,449**
State Taxes				
State Taxable Income	123,632,744	101,218,242	9,259,644	13,154,857
State Income Tax Rate	9.80%	9.80%	9.80%	9.80%
State Taxes before Credits	12,116,009	9,919,388	907,445	1,289,176
Less State Tax Credits	(559,000)	(559,000)		
Deferred State Tax Credits due to NOL	0	0	0	0
Total State Income Taxes	11,557,009	9,360,388	907,445	1,289,176
Federal Taxes				
Federal Sec 199 Production Deduction	38,298,210	34,023,749	2,401,265	1,873,197
Federal Taxable Income	73,777,524	57,834,106	5,950,934	9,992,484
Federal Income Tax Rate	35.00%	35.00%	35.00%	35.00%
Federal Tax before Credits	25,822,133	20,241,937	2,082,827	3,497,370
Less Federal Tax Credits	(53,724,549)	(45,486,352)	(4,264,461)	(3,973,736)
Deferred Federal Tax Credits due to NOL	(67,488,884)	(62,148,736)	(3,398,745)	(1,941,403)
Total Federal Income Taxes	(95,391,300)	(87,393,151)	(5,580,379)	(2,417,770)
Total Taxes				
Total Taxes Other than Income	408,149,941	355,076,042	23,755,450	29,318,449
Total Federal and State Income Taxes	(83,834,291)	(78,032,763)	(4,672,934)	(1,128,594)
Total Taxes	324,315,650	277,043,279	19,082,516	28,189,855

Data Vintage: 2016 rate case budget

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Xcel Energy			
Docket No.:	E002/GR-15-826		
Response To:	MN Department of Commerce	Information Request No.	1140
Requestor:	Nancy Campbell, Dale Lusti, Angela Byrne		
Date Received:	April 22, 2016		

Question:

Reference: N/A

Subject: North Dakota ITC

a) Please provide on a spreadsheet the calculations and resulting adjustments for both the 3-year and 5-year rate plans, which would assign 74% or the rate case Minnesota Jurisdictional allocated amount (consistent with the allocation of North Dakota wind facilities costs and North Dakota Property Taxes) for North Dakota ITC.

b) Please provide the allocation of North Dakota Wind facilities capital costs to Minnesota Jurisdiction by wind facility.

c) Please provide the allocation of North Dakota Wind facilities property taxes to Minnesota Jurisdiction by wind facility.

Response:

We note by way of background, that the ND ITC is a credit to North Dakota income tax pursuant to N.D.C.C. Section 57-38-01.8 that only offers a tax benefit to the extent the Company has an income tax liability in the State of North Dakota.

We also note that the Minnesota Cost of Service does not currently include a portion of the North Dakota income tax liability, which this credit would offset.

a) Please refer to Attachment A to this response for the 2016-2020 North Dakota Investment Tax Credit (NDITC) which is limited to the expected income tax liability in those years in North Dakota. Due to the extension of bonus depreciation in the 2015 Protecting Americans from Tax Hikes (PATH) Act, the Company does not expect to have taxable income in North Dakota until 2020. Therefore, there is no NDITC that the Company can utilize until 2020. Note these amounts will not be specifically known until North Dakota state tax returns are filed in each future year.

   Attachment A calculates the revenue requirements offset for the NDITCs if they were allocated to the Minnesota jurisdiction. Attachment A does not attempt to allocate a portion of the North Dakota income tax expense to Minnesota, as we currently have no regulatory basis to do so. However if Minnesota were to benefit from the North Dakota income tax credit, Minnesota should also bear a portion of the North Dakota income tax expense.

   For comparison purposes, Minnesota state tax law allows a Research and Experimentation (MN R&E) Credit which is applied directly to Minnesota state income taxes. If state-specific income tax credits were to be shared among all NSP jurisdictions, then the MN R&E Credit would be shared as well. Attachment A also shows the calculation of the MN R&E Credit allocated to the Minnesota jurisdiction such that the value is decreased to approximately 73.5 percent of the total credit. The 3-year and 5-year impact of sharing both of these tax credits is an increase of approximately $493,000 and $84,000, respectively, to the Minnesota electric retail jurisdiction revenue requirement.

   The Company's position with respect to the Minnesota treatment of NDITCs is contained in the Direct Testimony of Company witness Anne E. Heuer in Section IX. Compliance with Prior Commission Orders, Part E, Other Compliance Requirements, Item 6, North Dakota Income Tax Credits.

   The logic is that income taxes (state and federal) for jurisdictional cost of service are calculated on a stand-alone basis by applying the state-specific and federal defined deductions and credits to the calculation of current taxes. By consistently applying this stand-alone logic, Minnesota ratepayers are not asked to sponsor North Dakota current state income taxes and North Dakota ratepayers are not asked to sponsor Minnesota current state income taxes. For these reasons, the Company has not applied any North Dakota specific state tax credit to the calculation of Minnesota state and federal current income taxes in the jurisdictional cost of service study.

b-c) Please refer to Attachment B, pages 1 and 2 to this response for the revenue requirements of the Border Winds and Courtenay Wind projects, respectively. The amounts for each wind farm are shown for total Northern States Power Company and the amounts allocated to the Minnesota Jurisdiction. Please note that the presentation of the Border Winds revenue requirement is consistent with the base rate revenue requirement calculations while the Courtenay Wind revenue requirement calculation is consistent with the Renewable Energy Standard (RES) Rider method.

Border Winds capital related costs and property taxes are allocated to the Minnesota Jurisdiction based on the Energy allocator of 87.3278%. This percentage represents Minnesota's share of NSPM's portion of the revenue requirement. The Company also receives revenue through the Interchange Agreement from NSPW which is roughly 15 percent of the total NSPM revenue requirement (row 9).

The Courtenay Wind farm is recovered through the Renewable Energy Standard (RES) Rider. Therefore, capital costs and property taxes are allocated based on the Energy allocator and the Interchange Agreement Demand allocator (roughly 73.5%). The RES Rider applies the Interchange Agreement as a reduction in costs instead of an increase in other revenues, which is why there is no data on the Courtenay Wind Interchange Offset line item on Attachment B (row 9).

Witness: Anne E. Heuer
Preparer: Joanna Yugo
Title: Principal Rate Analyst
Department: Revenue Requirements
Telephone: 612-215-4633
Date: May 9, 2016

Northern States Power Company
NDITC vs. MN R E Credit
2016-2020

			ND Investment Tax Credit			MN R&E Credit			
	North Dakota Tax Liability	**North Dakota Tax Liability, Net of Federal**	**NSPM Total Revenue Requirement**	**MN Jurisdiction *(if allocated)***		**NSPM Total Revenue Requirement**	**MN Jurisdiction *(if allocated)***	**MN Jur Rev Req Difference**	
2016	$ -	$ -	$ -	$ -	2016	$ (619,734)	$ (455,433)	$ 164,300	
2017	-	-	-	-	2017	(619,734)	(455,433)	164,300	**3-year Total:**
2018	-	-	-	-	2018	(619,734)	(455,433)	164,300	$ 492,901
2019	-	-	-	-	2019	(619,734)	(455,433)	164,300	
2020	910,235	591,653	(1,009,130)	(737,119)	2020	(619,734)	(455,433)	(572,818)	
Total	**$ 910,235**	**$ 591,653**	**$ (1,009,130)**	**$ (737,119)**	**Total**	**$ (3,098,669)**	**$ (2,277,167)**	**$ 84,383**	**5-year Total**

Annual Revenue Requirement
Border Winds
2016-2018 MYRP plus 2019-2020 Fcst
(000's)

		Total Company (after Interchange)					MN Jurisdiction				
	Rate Analysis	2016	2017	2018	2019	2020	2016	2017	2018	2019	2020
1	Average Balances:										
2	Plant Investment	266,527	266,556	266,556	266,556	266,556	232,752	232,777	232,777	232,777	232,777
3	Depreciation Reserve	8,206	19,794	31,382	42,970	54,558	7,166	17,286	27,405	37,525	47,644
4	CWIP	-	-	-	-	-	-	-	-	-	-
5	Accumulated Deferred Taxes	27,493	54,283	68,476	76,266	82,608	24,009	47,404	59,799	66,602	72,140
6	Average Rate Base = line 1 - line 3 + line 4 - line 5	230,828	192,479	166,698	147,320	129,390	201,577	168,088	145,574	128,651	112,994
7											
8	Revenues:										
9	Interchange Agreement offset	(3,285)	(2,397)	(1,897)	(1,529)	(1,203)	(2,869)	(2,093)	(1,657)	(1,335)	(1,050)
10											
11	Expenses:										
12	Book Depreciation	11,588	11,588	11,588	11,588	11,588	10,119	10,119	10,119	10,119	10,119
13	Annual Deferred Tax	30,004	16,124	7,791	7,789	1,541	26,202	14,080	6,803	6,802	1,346
14	ITC Flow Thru	-	-	-	-	-	-	-	-	-	-
15	Property Taxes	700	700	700	700	700	611	611	611	611	611
16	subtotal expense = lines 12 thru 15	42,292	28,411	20,079	20,077	13,829	36,933	24,811	17,534	17,533	12,077
17											
18	Tax Preference Items:										
19	Tax Depreciation & Removal Expense	85,060	51,047	30,628	30,624	15,315	74,281	44,579	26,747	26,743	13,375
20	Tax Credits (enter as negative)	(11,283)	(11,969)	(11,980)	(11,981)	(12,019)	(9,853)	(10,452)	(10,462)	(10,463)	(10,496)
21	Avoided Tax Interest	-	-	-	-	-	-	-	-	-	-
22											
23	AFUDC	-	-	-	-	-	-	-	-	-	-
24											
25	Returns:										
26	Debt Return = line 6 x (line 44 + line 45)	5,171	4,350	3,767	3,315	2,950	4,515	3,799	3,290	2,895	2,576
27	Equity Return = line 6 x (line 46 + line 47)	12,138	10,122	8,766	7,747	6,804	10,583	8,825	7,643	6,754	5,932
28											
29	Tax Calculations:										
30	Equity Return = line 27	12,138	10,122	8,766	7,747	6,804	10,583	8,825	7,643	6,754	5,932
31	Taxable Expenses = lines 12 thru 14	41,592	27,711	19,379	19,377	13,129	36,321	24,200	16,923	16,921	11,466
32	plus Tax Additions = line 21	-	-	-	-	-	-	-	-	-	-
33	less Tax Deductions = (line 19 + line 23)	(85,060)	(51,047)	(30,628)	(30,624)	(15,315)	(74,281)	(44,579)	(26,747)	(26,743)	(13,375)
34	subtotal	(31,330)	(13,214)	(2,484)	(3,500)	4,618	(27,377)	(11,554)	(2,182)	(3,068)	4,023
35	Tax gross-up factor = t / (1-t) from line 50	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611
36	Current Income Tax Requirement = line 34 x line 35	(22,107)	(9,324)	(1,753)	(2,470)	3,259	(19,318)	(8,153)	(1,539)	(2,165)	2,839
37	Tax Credit Revenue Requirement = line 20 x line 35 + line 20	(19,244)	(20,414)	(20,433)	(20,435)	(20,500)	(16,806)	(17,828)	(17,844)	(17,845)	(17,902)
38	Total Current Tax Revenue Requirement = line 36+ line 37	(41,351)	(29,739)	(22,186)	(22,905)	(17,241)	(36,123)	(25,980)	(19,383)	(20,010)	(15,063)
39											
40	Total Capital Revenue Requirements	14,964	10,748	8,529	6,705	5,140	13,038	9,361	7,427	5,836	4,472
41	= line 16 + line 26 + line 27 + line 38 - line 23 + line 9										
42	O&M Expense	4,992	5,106	5,211	4,290	4,310	4,360	4,459	4,551	3,746	3,764
43	Total Revenue Requirements	19,957	15,854	13,740	10,995	9,450	17,398	13,820	11,978	9,583	8,236

	Capital Structure	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**
44	**Long Term Debt**	**2.2200%**	**2.2100%**	**2.2100%**	**2.1800%**	**2.2000%**
45	**Short Term Debt**	**0.0200%**	**0.0500%**	**0.0500%**	**0.0700%**	**0.0800%**
46	**Preferred Stock**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
47	**Common Equity**	**5.2500%**	**5.2500%**	**5.2500%**	**5.2500%**	**5.2500%**
48	**Required Rate of Return**	**7.4900%**	**7.5100%**	**7.5100%**	**7.5000%**	**7.5300%**
49	**PT Rate**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
50	**Tax Rate (MN)**	**41.3700%**	**41.3700%**	**41.3700%**	**41.3700%**	**41.3700%**
51	**MN JUR Energy**	**87.3278%**	**87.3278%**	**87.3278%**	**87.3278%**	**87.3278%**
52	**MN JUR Demand**	**87.3461%**	**87.3461%**	**87.3461%**	**87.3461%**	**87.3461%**
53	**IA Demand**	**84.1349%**	**84.1349%**	**84.1349%**	**84.1349%**	**84.1349%**

Annual Revenue Requirement
Courtenay Wind
Recovery in RES Rider
(000's)

		Total Company					MN Jurisdiction				
	Rate Analysis	2016	2017	2018	2019	2020	2016	2017	2018	2019	2020
1	Average Balances:										
2	Plant Investment	295,977	295,977	295,977	295,977	295,977	217,408	217,417	217,414	217,413	217,411
3	Depreciation Reserve	601	13,089	25,578	38,066	50,555	441	9,615	18,788	27,962	37,135
4	CWIP	-	-	-	-	-	-	-	-	-	-
5	Accumulated Deferred Taxes	20,413	53,264	71,131	79,991	88,803	14,994	39,127	52,251	58,758	65,231
6	Average Rate Base = line 1 - line 3 + line 4 - line 5	274,963	229,623	199,268	177,920	156,619	201,972	168,676	146,375	130,693	115,045
7											
8	Revenues:										
9	Interchange Agreement offset										
10											
11	Expenses:										
12	Book Depreciation	601	12,488	12,488	12,488	12,488	441	9,174	9,174	9,174	9,173
13	Annual Deferred Tax	20,688	32,851	17,867	8,859	8,813	15,196	24,132	13,124	6,508	6,473
14	ITC Flow Thru	-	-	-	-	-	-	-	-	-	-
15	Property Taxes	-	904	904	904	904	-	664	664	664	664
16	subtotal expense = lines 12 thru 15	21,289	46,244	31,259	22,252	22,205	15,637	33,970	22,962	16,345	16,311
17											
18	Tax Preference Items:										
19	Tax Depreciation & Removal Expense	57,959	92,984	56,266	34,193	34,079	42,574	68,303	41,331	25,117	25,033
20	Tax Credits (enter as negative)	(35)	(14,523)	(15,450)	(15,450)	(15,531)	(25)	(10,566)	(11,241)	(11,241)	(11,300)
21	Avoided Tax Interest	6,665	-	-	-	-	4,896	-	-	-	-
22											
23	AFUDC	-	-	-	-	-	-	-	-	-	-
24											
25	Returns:										
26	Debt Return as Calculated in RES Rider	4,168	5,727	4,868	4,281	3,797	3,061	4,207	3,576	3,145	2,789
27	Equity Return as Calculated in RES Rider	9,364	12,867	10,937	9,618	8,531	6,878	9,452	8,034	7,065	6,266
28											
29	Tax Calculations:										
30	Equity Return = line 27	9,364	12,867	10,937	9,618	8,531	6,878	9,452	8,034	7,065	6,266
31	Taxable Expenses = lines 12 thru 14	21,289	45,340	30,355	21,348	21,301	15,637	33,306	22,298	15,681	15,647
32	plus Tax Additions = line 21	6,665	-	-	-	-	4,896	-	-	-	-
33	less Tax Deductions = (line 19 + line 23)	(57,959)	(92,984)	(56,266)	(34,193)	(34,079)	(42,574)	(68,303)	(41,331)	(25,117)	(25,033)
34	subtotal	(20,642)	(34,777)	(14,974)	(3,227)	(4,247)	(15,163)	(25,546)	(10,999)	(2,371)	(3,120)
35	Tax gross-up factor = t / (1-t) from line 45	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611
36	Current Income Tax Requirement = line 34 x line 35	(14,565)	(24,539)	(10,566)	(2,277)	(2,997)	(10,699)	(18,026)	(7,761)	(1,673)	(2,201)
37	Tax Credit Revenue Requirement = line 20 x line 35 + line 20	(60)	(24,771)	(26,352)	(26,352)	(26,490)	(43)	(18,022)	(19,173)	(19,173)	(19,273)
38	Total Current Tax Revenue Requirement = line 36+ line 37	(14,625)	(49,310)	(36,917)	(28,629)	(29,487)	(10,742)	(36,048)	(26,934)	(20,845)	(21,475)
39											
40	Total Revenue Requirements	20,195	15,528	10,147	7,522	5,046	14,835	11,580	7,638	5,710	3,892
41	= line 16 + line 26 + line 27 + line 38 - line 23 + line 9										
42	O&M Expense	1,186	6,650	6,958	6,871	6,235	872	4,886	5,112	5,049	4,581
43	Transmission Interconnection Expense	273	2,186	2,186	2,186	2,186	201	1,607	1,607	1,607	1,607
44	Total Revenue Requirements	21,655	24,365	19,290	16,580	13,468	15,907	18,073	14,357	12,365	10,080
45	**Tax Rate (MN)**	**41.3700%**	**41.3700%**	**41.3700%**	**41.3700%**	**41.3700%**					
46	**MN JUR Energy/Demand Composite**	**87.3054%**	**87.3093%**	**87.3081%**	**87.3075%**	**87.3068%**					
47	**MN JUR Energy**	**87.3278%**	**87.3278%**	**87.3278%**	**87.3278%**	**87.3278%**					
48	**MN JUR Demand**	**87.3461%**	**87.3461%**	**87.3461%**	**87.3461%**	**87.3461%**					
49	**IA Demand**	**84.1349%**	**84.1349%**	**84.1349%**	**84.1349%**	**84.1349%**					
50	**IA Energy**	**83.3146%**	**83.3146%**	**83.3146%**	**83.3146%**	**83.3146%**					

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

Xcel Energy
Docket No.: E002/GR-15-826
Response To: MN Department of Commerce Information Request No. 198
Requestor: Nancy Campbell, Dale Lusti, Angela Byrne
Date Received: April 15, 2016

Question:
Reference: Direct Testimony of Steven Mills p 5 and Schedule 2
Subject: O&M Expenses

a) On page 99, the Company noted a 2016 O&M budget of $164.6 million and ($143.7 million), however, on Schedule 2 the Company shows $164.6 million and $120.86 million, please explain the differences in these amounts.
b) Please provide support for the allocators used to get from Total Company O&M and Capital Energy to Minnesota Jurisdictional.
c) Please update both pages of Schedule 2 O&M Expenses, by adding the following information: 2015 actuals, 2017 budget/test year, 2018 budget/test year, and O&M expense levels approved in last two rate cases.

Response:
a) The Company assumes that the question refers to the amounts included on page 69 of the Direct Testimony of Mr. Steven Mills, as these numbers do not appear on page 99 of Mr. Mills's testimony. The Minnesota Jurisdiction O&M amount referenced on page 69 ($143.7 million) is not shown net of Interchange Billings to NSPW. However, as noted on page 2 of Mr. Mills's Direct Testimony and in the footnote on Exhibit___(SHM-1), Schedule 2, the Minnesota Jurisdiction O&M amount shown on Exhibit___(SHM-1), Schedule 2 ($120.86 million) is net of Interchange Agreement billings to NSPW. Please see the table below for a reconciliation of the amounts shown on page 69 of Mr. Mills's Direct Testimony and the amounts shown in Exhibit___(SHM-1), Schedule 2.

	2016 Budget	Composite Allocator	
NSPM Total	$ 164.6		
MN Jurisdiction	$ 143.7	87.30%	Combination of Demand and Jurisdictional allocators applied to recoverable NSPM expenses
MN Jurisdiction Net of Interchange	$ 120.9	73.45%	Estimated based on Demand Interchange Allocator

b) Production expenses are allocated to the NSPM state jurisdictions based on the FERC code in which they are recorded. If an expense is considered fixed in nature it is allocated to the state jurisdiction based on the demand allocator. Those production expenses considered variable in nature are allocated using the energy allocation factor. Following is the list of the FERC codes for production O&M expense and the jurisdictional allocator assigned to each:

FERC Code min	FERC Code max	Allocator
500	500	Demand
501	501	Energy
502	507	Demand
510	510	Energy
511	511	Demand
512	513	Energy
514	517	Demand
518	518	Energy
519	525	Demand
528	528	Energy
529	529	Demand
530	531	Energy
532	539	Demand
540	541	Energy
543	543	Demand
544	544	Energy
545	546	Demand
547.1	547.1	Demand
547.2	547.2	Demand
548	555.01	Demand
555.02	555.02	Energy
556	556	Demand
557	557	Energy

These allocation methods are discussed in the Direct Testimony of Mr. Adam R. Dietenberger, Exhibit___(ARD-1), Schedule 3, NSPM's Cost Assignment and Allocation Manual (CAAM). Support for the calculation of each allocator is included in Volume 4A, Test Year Workpapers Base Data, Tab VII. Budget Allocators.

In addition to the allocation of production O&M expenses to NSPM state jurisdictions, production expenses are also shared with Northern States Power Company-Wisconsin (NSPW) under the terms of the FERC regulated Interchange Agreement (IA) tariff. The allocation of costs between NSPM and NSPW generally follows the same methodology and process as described above for allocation of costs between NSPM state jurisdictions.

c) Attachment A includes the requested updates to Exhibit___(SHM-1), Schedule 2.

Witness:	Steven Mills
Preparer:	Aaron Brixius/Mary Pope
Title:	Operations Support Manager/Senior Rate Analyst
Department:	Energy Supply Operations/Revenue Requirements
Telephone:	612-330-5794/612/330-6574
Date:	April 28, 2016

Northern States Power Company

Northern States Power Company - MN

	As shown in Schedule 2								DOC-198		
	2012 Actual	**2013 Budget**	**2013 Actual**	**2014 Budget**	**2014 Actual**	**2012-14 Avg**	**2015 Forecast**	**2016 Budget**	**2015 Actual**	**2017 Budget**	**2018 Budget**
Angus Plant	2,155,245	2,922,382	2,636,225	2,106,680	2,660,961	2,484,144	2,115,105	2,963,959	2,251,195	2,212,319	2,246,738
AS King Plant	23,313,901	28,562,281	34,693,165	31,420,428	34,154,367	30,720,478	29,474,705	29,001,444	28,110,050	26,903,547	33,414,716
Black Dog Station	16,228,893	13,716,336	18,866,634	14,366,898	17,068,098	17,387,875	11,514,142	9,035,117	10,858,886	7,827,422	8,763,600
Blue Lake Plant	715,624	845,923	959,611	856,462	1,576,536	1,083,924	1,217,643	1,243,854	1,089,689	1,314,215	1,426,681
Borders Wind						-	1,162,483	4,992,341	448,831	5,011,239	5,164,019
Grand Meadows Wind	2,620,590	2,291,618	3,001,544	2,965,868	3,554,127	3,058,754	2,929,923	3,291,297	2,648,774	3,347,696	3,742,140
Granite City Plant	43,000	126,400	134,611	130,964	204,683	127,431	135,009	145,207	108,460	146,765	201,861
High Bridge Plant	6,060,014	6,206,857	6,434,494	6,417,780	7,759,002	6,751,170	6,923,852	7,086,065	6,952,567	7,242,928	10,215,300
Inver Hills Plant	1,481,471	882,287	909,103	1,413,466	1,230,173	1,206,916	1,214,267	1,401,432	1,085,919	1,474,303	1,482,154
Key City Plant	51,067	74,200	25,154	77,160	52,715	42,979	48,170	-	12,304		
Minnesota Valley Plant	23,444	266,930	81,551	271,930	66,927	57,307	227,043	152,353	33,200	156,250	200,088
Nobles Wind	3,592,959	3,924,948	3,394,254	4,805,983	4,376,853	3,788,022	4,896,547	4,940,889	4,215,853	5,018,014	5,189,875
Pleasant Valley Wind						-	1,698,607	6,849,549	676,008	6,913,252	8,072,345
Red Wing Plant	4,994,852	5,036,530	5,637,699	5,989,718	6,959,023	5,863,858	6,489,527	5,274,620	6,569,849	5,356,906	5,736,504
Riverside Plant	6,947,905	7,208,523	8,511,136	7,261,277	7,989,790	7,816,277	7,502,242	6,862,844	6,649,163	11,693,975	7,413,338
Sherco Plant	47,377,374	52,568,694	54,868,018	44,773,946	46,753,842	49,666,411	56,384,864	56,445,283	56,522,761	53,820,395	57,771,512
St. Anthony Falls	437,734	519,086	716,968	521,041	579,909	578,204	373,640	496,119	537,540	504,562	515,138
Wilmarth Plant	5,603,907	4,775,834	5,230,572	5,618,507	6,372,772	5,735,750	5,476,624	5,648,159	5,475,924	7,048,683	6,168,899
Disbursed Generation	79,490	40,800	29,490	29,865	22,972	43,984	56,115	61,200	10,013	61,200	49,200
Other Energy Supply O&M	31,294,425	28,068,209	15,952,727	30,101,749	15,617,251	20,954,801	18,658,573	18,680,793	16,883,979	18,876,934	10,889,399
Total	**$ 153,021,895**	$ 158,037,838	$ 162,082,956	$ 159,129,722	$ 157,000,001	$ 157,368,284	$ 158,499,081	$ 164,572,525	$ 151,140,965	$ 164,930,605	$ 168,663,507

Minnesota Jurisdiction net of Interchange billings to NSPW

	As shown in Schedule 2								DOC-198					
	2012 Actual	**2013 Budget**	**2013 Actual**	**2014 Budget**	**2014 Actual**	**2012-14 Avg**	**2015 Forecast**	**2016 Budget**	**2013 TY**	**2014 TY**	**2015 Step**	**2015 Actual**	**2017 Budget**	**2018 Budget**
Angus Plant	1,611,721	2,180,808	1,960,339	1,566,104	1,974,888	1,848,983	1,563,583	2,177,718	2,180,808	1,566,104	1,566,104	1,661,426	1,625,464	1,650,755
AS King Plant	17,357,447	21,178,395	25,690,231	23,344,240	25,348,844	22,798,841	21,774,494	21,308,276	21,178,395	23,344,240	23,344,240	20,772,764	19,766,884	24,550,844
Black Dog Station	12,079,437	10,196,663	13,993,161	10,677,090	12,667,599	12,913,399	8,507,235	6,638,382	10,196,663	10,677,090	10,677,090	8,016,666	5,751,050	6,438,895
Blue Lake Plant	535,159	631,266	713,586	636,691	1,170,064	806,270	900,149	913,902	631,266	636,691	636,691	804,222	965,600	1,048,233
Borders Wind							859,371	3,668,031	-	-	-	331,249	3,681,915	3,794,167
Grand Meadows Wind	1,959,756	1,710,108	2,232,003	2,204,828	2,637,777	2,276,512	2,165,957	2,418,221	1,710,108	2,204,828	2,204,828	1,954,876	2,459,658	2,749,468
Granite City Plant	32,156	94,324	100,097	97,358	151,909	94,721	99,805	106,688	94,324	97,358	97,358	80,048	107,832	148,314
High Bridge Plant	4,532,334	4,631,834	4,784,804	4,770,973	5,758,528	5,025,222	5,051,033	5,182,439	4,631,834	4,770,973	4,770,973	5,130,646	5,321,612	7,505,506
Inver Hills Plant	1,107,884	658,401	676,026	1,050,772	913,000	898,970	897,649	1,029,670	658,401	1,050,772	1,050,772	801,438	1,083,217	1,088,981
Key City Plant	38,190	55,372	18,706	57,361	39,123	32,006	35,610	-	55,372	57,361	57,361	9,080		
Minnesota Valley Plant	17,533	198,691	45,768	202,109	49,671	37,657	167,843	111,941	198,691	202,109	202,109	24,504	114,802	147,011
Nobles Wind	2,686,918	2,928,969	2,524,027	3,572,767	3,248,380	2,819,775	3,619,793	3,630,227	2,928,969	3,572,767	3,572,767	3,111,426	3,686,893	3,813,165
Pleasant Valley Wind							1,255,703	5,032,580	-	-	-	498,913	5,079,386	5,931,009
Red Wing Plant	3,717,328	3,741,033	4,177,333	4,450,509	5,164,733	4,353,131	4,788,056	3,875,435	3,741,033	4,450,509	4,450,509	4,855,264	3,935,887	4,214,793
Riverside Plant	5,195,236	5,379,324	6,329,040	5,398,036	5,929,802	5,818,026	5,545,976	5,042,350	5,379,324	5,398,036	5,398,036	4,907,371	8,591,936	5,446,820
Sherco Plant	35,104,078	38,924,230	40,543,302	33,224,750	34,444,584	36,697,321	41,609,771	41,429,522	38,924,230	33,224,750	33,224,750	41,689,338	39,500,942	42,403,942
St. Anthony Falls	327,117	386,377	532,113	387,267	430,393	429,874	276,197	364,515	386,377	387,267	387,267	396,790	370,718	378,488
Wilmarth Plant	4,171,092	3,542,831	3,877,797	4,174,553	4,729,739	4,259,543	4,046,947	4,149,882	3,542,831	4,174,553	4,174,553	4,045,886	5,178,892	4,532,486
Disbursed Generation	59,445	30,447	21,929	22,202	17,049	32,808	41,484	44,966	30,447	22,202	22,202	7,389	44,966	36,149
Other Energy Supply O&M	23,269,891	20,874,167	11,797,555	22,366,132	11,526,273	15,531,240	13,829,984	13,735,286	20,874,167	22,366,132	22,366,132	12,407,698	13,855,462	7,986,765
Rate Case Adjustments									(9,898,000)	(2,265,038)	2,114,036			
Total	**$ 113,802,722**	$ 117,343,240	$ 120,017,817	$ 118,203,742	$ 116,202,356	$ 116,674,298	$ 117,036,640	$ 120,860,031	$ 107,445,240	$ 115,938,704	$ 120,317,778	$ 111,506,994	$ 121,123,116	$ 123,865,791

Notes:
Rate case adjustments impact MN Electric Jurisdiction only, and are not necessarily plant specific.

Northern States Power Company

Docket No. E002/GR-15-826
Exhibit____(SHM-1), Schedule 2
Page 2 of 2

Northern States Power Company - MN - Excluding Courtenay Wind

	As shown in Schedule 2								DOC-198		
	2012 Actual	**2013 Budget**	**2013 Actual**	**2014 Budget**	**2014 Actual**	**2012-14 Avg**	**2015 Budget**	**2016 Budget**	**2015 Actual**	**2017 Budget**	**2018 Budget**
Internal Labor	78,136,953	78,666,827	82,195,060	78,404,551	76,409,483	78,913,832	75,050,738	73,588,104	74,244,433	72,109,169	74,798,011
Contract Labor	33,628,098	27,995,399	34,977,836	29,447,898	29,282,871	32,629,602	35,184,060	42,151,364	32,692,539	41,602,373	47,064,257
Materials	25,831,966	26,103,908	27,431,920	27,651,164	31,180,026	28,147,971	24,352,211	23,825,887	23,526,169	29,126,343	21,001,573
Commodities	8,057,416	15,397,680	7,706,140	13,862,233	8,879,685	8,214,414	14,399,726	11,873,531	9,746,367	10,961,091	13,778,399
Other	7,367,462	9,874,024	9,772,000	9,763,877	11,247,936	9,462,466	10,414,967	13,133,639	10,931,457	11,131,629	12,021,268
Total	153,021,895	$ 158,037,838	$ 162,082,956	$ 159,129,722	$ 157,000,001	$ 157,368,284	$ 159,401,702	$ 164,572,525	$ 151,140,965	$ 164,930,605	$ 168,663,508

Minnesota Jurisdiction net of Interchange billings to NSPW

	As shown in Schedule 2								DOC-198					
	2012 Actual	**2013 Budget**	**2013 Actual**	**2014 Budget**	**2014 Actual**	**2012-14 Avg**	**2015 Budget**	**2016 Budget**	**2013 TY**	**2014 TY**	**2015 Step**	**2015 Actual**	**2017 Budget**	**2018 Budget**
Internal Labor	58,095,019	58,450,933	60,855,946	58,264,628	56,660,801	58,537,255	55,342,772	54,067,502	58,450,933	58,264,628	58,264,628	54,731,135	52,980,883	54,956,464
Contract Labor	25,036,542	20,747,985	25,908,718	21,865,017	21,544,350	24,163,203	25,410,674	30,953,783	15,715,247	21,865,017	21,865,017	24,160,347	30,550,420	34,563,438
Materials	19,157,731	19,305,683	20,301,177	20,516,863	23,072,922	20,843,943	17,479,929	17,479,182	19,305,683	20,516,863	20,516,863	17,364,259	21,373,599	15,404,075
Commodities	6,024,655	11,490,442	5,729,700	10,305,154	6,590,301	6,114,885	10,633,745	8,723,858	6,625,180	8,040,116	12,419,190	7,193,391	8,053,460	10,123,425
Other	5,488,775	7,348,197	7,222,276	7,252,080	8,333,982	7,015,011	8,731,130	9,635,706	7,348,197	7,252,080	7,252,080	8,057,862	8,164,754	8,818,389
Total	$ 113,802,722	$ 117,343,240	$ 120,017,817	$ 118,203,742	$ 116,202,356	$ 116,674,298	$ 117,598,250	$ 120,860,031	$ 107,445,240	$ 115,938,704	$ 120,317,778	$ 111,506,994	$ 121,123,116	$ 123,865,791

Note: the jurisdictional values in testimony no not reflect the interchange offsets to NSPW; those values are shown in this Schedule.
Rate case adjustments impact MN Electric Jurisdiction only.

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Xcel Energy			
Docket No.:	E002/GR-15-826		
Response To:	MN Department of Commerce	Information Request No.	168
Requestor:	Nancy Campbell, Angela Byrne, Dale Lusti		
Date Received:	April 1, 2016		

Question:

Reference: Direct Testimony of Anne Heuer & Charles Burdick

Subject: All 2016 to 2018 rate case adjustments

a) Please calculate the 2019 and 2020 revenue requirement impacts for all rate case adjustments for 2016 to 2018, including supporting calculations and narrative explanations.

b) For each adjustment explain why the Company considers the adjustment to be appropriate or not appropriate for 2019 and 2020 for purposes of the 5-year rate plan. As an example, DOC notes that adjustment A26 in Volume 4B (remaining life depreciation adjustments for NSPW generation approved by Wisconsin) is a good example of an adjustment that provided information supporting 2016, 2017 and 2018 adjustments by test year and should be extended for 2019 and 2020.

Response:

The Company's five-year forecast provided in our initial application was the starting point for development of our five-year settlement offer. The five-year forecast was developed similarly to the 2016 Test Year. Specifically, we included year five of the corporate forecast[1] for the Minnesota Electric Jurisdiction which shows a $474 million revenue deficiency. We then applied the same regulatory and ratemaking adjustment principles as were applied to the 2016 Test Year to arrive at a $428 million

[1] See Company witness Mr. Gregory J. Robinson's Direct Testimony for the forecast process.

revenue need in 2020. Please see Attachment A to this response for a summary of adjustments applied to the 2019 and 2020 forecasts. We provide additional discussion of these adjustments in our response to parts a) and b) below.

Regarding the structure of our five-year offer, once we determined the revenue need over the five-year period, we then evaluated this forecast in light of the multi-year rate plan legislation, which enables additional tools for creating multi-year rate plans. To recognize the value to customers and to the Company of rate certainty over the five years, we developed a discounted settlement offer of $382 million over the five years following a smoothed rate pattern for 2017-2020. The result is a proposed rate shape that is informed by the forecast but is not the result of a specific cost of service study.

In this case, we have noticed and our request is for a three-year rate plan. Our five-year offer was intended as the beginning of a possible settlement discussion. We encourage parties to present their ideas around this offer informally or formally through testimony so that their perspectives may be considered in potential settlement discussions. For example, material updates related to purchased demand contracts or depreciation rates could trigger consideration of modifications to the five-year offer as part of settlement discussions.

Please see Mr. Aakash H. Chandarana's Direct Testimony, pages 73-79, and the Company's response to Information Request No. DOC-133 for additional information regarding the five-year settlement offer.

a) and b)

> As noted above, Attachment A provides a summary of adjustments applied to the 2019 and 2020 forecast. The purpose of each ratemaking adjustment in the 2019 and 2020 forecasts is described by Ms. Anne E. Heuer in her Direct Testimony. Please see Volume 3, Required Information, II. Required Financial Information, Section 8, Five Year Forecast, Schedule C, pages 4-6, and Schedule D, pages 10-16 for rate base and income statement bridge schedules for the 2019 and 2020 forecast. In the 2019 and 2020 forecasts, certain adjustments remain at the 2016 level as they represent items that are not expected to change from year to year. Other adjustments follow the forecasted amounts for 2019 and 2020.
>
> As discussed above, the five-year settlement offer is not cost of service based, and therefore there are no specifically identified revenue requirements impacts related to these adjustments.

Witness:	Charles R. Burdick and Aakash Chandarana
Preparer:	Charles R. Burdick / Joanna M. Yugo
Title:	Manager of Revenue Analysis / Principal Rate Analyst
Department:	Revenue Requirements North / Revenue Requirements North
Telephone:	612-330-6646 / 612-215-4633
Date:	April 21, 2016

XCEL ENERGY -- MN RATE CASE ADJUSTMENT SUMMARY

Revenue deficiency in $ millions	2016	2017	2018	2019	2020	Workpaper	Testimony Ref	Bus Area Testimony Ref
Base Data at last authorized 9.72% ROE	$ 165.9	$ 194.6	$ 246.7	$ 409.3	$ 474.0			
Typical regulatory adjustments:								
Advertising	(2.7)			(2.9)	(3.0)	WP A-2	Heuer Direct Page 71	Heuer Sch 15
Customer Deposits Expense	0.0			0.0	0.0	WP A-3	Heuer Direct Page 73	
Dues: Chamber of Commerce	0.2			0.2	0.2	WP A-4	Heuer Direct Page 73	
Dues: Professional Associations	(0.0)			(0.0)	(0.0)	WP A-5	Heuer Direct Page 74	Heuer Sch 16
Economic Development Admin	0.0			0.0	0.0	WP A-6	Heuer Direct Page 74	Heuer Sch 17
Economic Development Donations	0.1			0.1	0.1	WP A-7	Heuer Direct Page 76	Heuer Sch 17
Foundation Admin	(0.3)			(0.3)	(0.3)	WP A-8	Heuer Direct Page 77	
Foundation and Other Donations	1.6			1.7	1.7	WP A-9	Heuer Direct Page 77	
Incentive Compensation	(12.6)			(13.8)	(14.3)	WP A-10	Heuer Direct Page 78	Lowenthal Direct, Pgs 8-9
Investor Relations	(0.5)			(0.5)	(0.5)	WP A-11	Heuer Direct Page 78	Van Abel Direct Pgs 7-8
Monticello LCM/EPU Return	(19.7)			(15.1)	(13.7)	WP A-12	Heuer Direct Page 79	
Nobles Amounts over CON	(0.3)			(0.2)	(0.2)	WP A-13	Heuer Direct Page 79	
Pension: Non Qualified	(1.4)			(0.9)	(0.9)	WP A-14	Heuer Direct Page 80	
Rate Case Adjustments:								
Black Dog Screenhouse (data update)	0.6			(0.3)	(0.3)	WP A-1	Heuer Direct Page 71	Mills Direct Pgs 31-32, 38
Aviation	(1.9)			(2.0)	(2.0)	WP A-15	Heuer Direct Page 81	O'Hara Direct Pgs 3, 8, 28, 35
Bad Debt Expense	(0.7)			(1.3)	(1.1)	WP A-16	Heuer Direct Page 82	
CIP Approved Program Levels	0.0			-	-	WP A-17	Heuer Direct Page 82	
CIP Incentive	23.7			23.7	23.7	WP A-18	Heuer Direct Page 83	
Employee Expenses	(1.6)			(1.6)	(1.6)	WP A-19	Heuer Direct Page 84	O'Hara Pgs 23-28
Like Kind Exchange Program	(0.3)			(0.3)	(0.3)	WP A-20	Heuer Direct Page 84	Perkett Direct Pg 59-62
Nuclear Retention	(0.8)			(0.0)	(0.0)	WP A-21	Heuer Direct Page 85	O'Connor pg 141, Lowenthal pg 8
Other Revenue 3 Year Average	(1.1)			(1.9)	(1.9)	WP A-22	Heuer Direct Page 85	
Retiree Medical: Discount Rate	(0.4)			(0.3)	(0.3)	WP A-23	Heuer Direct Page 86	Schrubbe Direct Pgs 70-74
Pension Smoothing	0.0			-	-	WP A-24	Heuer Direct Page 87	Schrubbe Direct Page 14
Remaining Life Study: NSPM	1.0			11.0	10.2	WP A-25	Heuer Direct Page 87	Perkett Direct Pg 29
Remaining Life Study: NSPW	(4.2)			(7.8)	(13.1)	WP A-26	Heuer Direct Page 88	
Trading: Asset-Based Margin	17.2			18.4	17.4	WP A-27	Heuer Direct Page 89	
Trading: Non Asset-Based Admin	(1.0)			(1.0)	(1.0)	WP A-28	Heuer Direct Page 89	Heuer Schedule 18
Trading: Non Asset-Based Margin	3.1			3.2	3.2	WP A-29	Heuer Direct Page 90	
XES Allocation on Labor Hours	(1.5)			(1.5)	(1.5)	WP A-30	Heuer Direct Page 90	Dietenberger Direct Pgs 14-15
Amortizations:								
PI EPU Recovery	3.5			3.5	3.5	WP A-31	Heuer Direct Page 91	Heuer Sch 21
Rate Case Expenses	1.1					WP A-32	Heuer Direct Page 92	Heuer Sch 22
Sherco 3 Depr Deferral	1.1			1.0	1.0	WP A-33	Heuer Direct Page 93	
Transco Costs	(0.0)					WP A-34	Heuer Direct Page 94	
Rider Removals:								
Rider: RES	0.1			0.0	(0.0)	WP A-35	Heuer Direct Page 94	
Rider: TCR	(0.2)			0.1	(0.0)	WP A-36	Heuer Direct Page 95	
Windsource	0.2			0.7	0.6	WP A-37	Heuer Direct Page 98	Peppin Direct Page 39
Forecast Increases:								
Capital Forecast		66.6	47.0			WP M1	Burdick Direct Page 15	Perkett pg 8, Robinson pg 11
Other Rate Base and Nonplant		0.4	0.5			WP M2	Burdick Direct Page 22	
Purchased Demand		(4.3)	(4.0)			WP M3	Burdick Direct Page 23	
Bad Debt Expense		(0.2)	(0.2)			WP M3	Burdick Direct Page 24	Gersack Direct Pg 26 & Sch 7
FERC 925 & 926		2.0	2.6			WP M3	Burdick Direct Page 25	Schrubbe Pgs 10-11, 97
Non-Decoupled Sales		(4.8)	(5.2)			WP M4	Burdick Direct Page 27	Huso Direct Page 2-7
Change in TCR Rider Revenue		1.5	1.4			WP M4	Burdick Direct Page 28	
Transmission Rev/Exp		(1.1)	(0.9)			WP M3	Burdick Direct Page 29	Benson Pg 123
Escalated Increases:								
Escalated O&M		16.5	16.5			WP M5	Burdick Direct Page 30	
Non-Retail Revenue		(0.9)	(0.4)			WP M6	Burdick Direct Page 37	
Secondary Calculations:								
ADIT Prorate for IRS	6.3			1.3	(0.2)	WP A-38	Heuer Direct Page 99	Heuer Sch 23
Cash Working Capital	1.4	(0.4)	(0.4)	(12.9)	(12.9)	WP A-39	Heuer pg 100, Burdick pg 38	
Change in Cost of Capital (10.00% ROE)	20.0	1.3	(0.2)	19.7	20.0	WP A-40	Heuer pg 101, Burdick pg 40	
Net Operating Loss	(1.4)	(24.5)	(6.5)	(49.6)	(58.7)	WP A-41	Heuer pg 102, Burdick pg 38	
TOTAL	**$ 194.6**	**$ 246.7**	**$ 297.1**	**$ 379.7**	**$ 427.7**			
incremental	$ 194.6	$ 52.1	$ 50.5	$ 82.5	$ 48.0	$ 427.7	Burdick Sch 13	
% increase over 2016 present revenues	6.4%	1.7%	1.7%	2.7%	1.6%	14.1%	Burdick Sch 13	
Settlement Offer Discount	$ (30.9)				$ (14.6)			
Settlement Offer Reshape	$ -	$ 2.6	$ 4.1	$ (27.9)	$ 21.2			
Settlement Offer, cumulative	$ 163.7	$ 218.3	$ 272.9	$ 327.5	$ 382.1			
incremental	163.7	$ 54.6	$ 54.6	$ 54.6	$ 54.6	$ 382.1	Chandarana pg 74	
% increase over 2016 present revenues	5.4%	1.8%	1.8%	1.8%	1.8%	12.6%	Chandarana pg 74	

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Xcel Energy
Docket No.: E002/GR-15-826
Response To: MN Department of Commerce Information Request No. 1121
Requestor: Nancy Campbell, Dale Lusti, Angela Byrne
Date Received: April 15, 2016

Question:
Reference: Direct Testimony of Steven Mills p 103
Subject: Other O&M

Please provide support for your land easements costs – actual 2015 and projected test year 2016 to 2018, and explain any differences of more than 5%.

Response:
Please see Attachment A to this response for the Company's 2015-18 land easement cost budgets and actual 2015 easement costs. Land easement contracts and the associated annual payments are established during the development phase of wind farm projects and then transferred to NSP as part of the wind farm sale agreement. The landowner agreements typically include multiple payment options for the land owner to choose from, such as fixed, CPI escalation, or a percentage of wind farm revenue based on generation. These variables are reflected in the 2016-18 budget estimates.

In general, our land easement costs continue to increase as we add wind generation capacity to our portfolio. Because the Courtenay Wind facility is not expected to be placed in service until late 2016, the Company budgeted O&M payments beginning in 2017; therefore, no land easement costs were budgeted or paid for the Courtenay Wind facility in 2015 and 2016.

Since our test and plan year budgets for land easement costs have not changed, we interpret the specific request for explanation of any variations of more than 5 percent as relating to variances between 2015 budgeted and 2015 actual land easement costs. The variances of 5 percent or more between 2015 actuals and 2015 budget pertained to our new Pleasant Valley and Border Winds facilities. Although these projects were completed and placed in service in 2015 as expected, their completion took place two months later than the original schedule. This delay meant that no land easement payments were required for either wind farm in 2015. Our 2016-2018 budgets are based on three full years of land easement payments for these facilities, and were not affected by the delay in placing Pleasant Valley and Border Winds in service later in 2015 than expected.

Witness:	Steven H. Mills
Preparer:	Aaron Brixius
Title:	Operations Support Manager
Department:	Energy Supply Operations
Telephone:	612-330-5794
Date:	April 26, 2016

	2015 Actuals	2015 Budget	2015 Variance	2016	2017	2018
Grand Meadow	$ 457,671	$ 463,623	*1.3%*	$ 472,370	$ 481,118	$ 495,552
Nobles	$ 701,340	$ 705,307	*0.6%*	$ 718,615	$ 731,922	$ 753,880
Border Winds	$ -	$ 141,713	*100.0%*	$ 566,853	$ 566,853	$ 566,853
Pleasant Valley	$ -	$ 396,997	*100.0%*	$ 1,588,917	$ 1,589,862	$ 1,589,862
Courtenay Wind	$ -	$ -		$ -	$ 1,200,000	$ 1,205,000
Total MN Wind	$ 1,159,011	$ 1,707,640		$ 3,346,755	$ 4,569,755	$ 4,611,147

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Xcel Energy			
Docket No.:	E002/GR-15-826		
Response To:	Department of Commerce	Information Request No.	1188
Requestor:	Nancy Campbell		
Date Received:	May 11, 2016		

Question:

Reference: Direct Testimony of Timothy O'Connor p 132, Table 7

Subject: Nuclear Operations Non-Outage O&M Costs

Please update Table 7 by replacing 2015 forecasted costs with 2015 actual costs, and add a column with 2013 Test Year amounts.

Response:

Attachment A to this request is an update of O'Connor Table 7, replacing 2015 forecasted costs with 2015 actual costs, and adding a column with 2013 Test Year amounts.

Witness:	Timothy J. O'Connor
Preparer:	Linda Erickson
Title:	Sr. Director, Finance & Nuclear Controller
Department:	Nuclear Finance
Telephone:	612-330-7862
Date:	May 23, 2016

Nuclear Operations Business Area O&M Costs - Non-Outage (Update to O'Connor Table 7)
NSPM Electric

$ in Millions	2012 Actuals	2013 Test Year Budget Requested	2013 Actual	2014 Test Year Budget Requested	2014 Actual	2015 Actual	2016 Test Year Budget	Average Annual Change: 2014 to 2016
Site Costs (Non-Outage)								
A. Internal Labor	130.3	131.6	139.5	155.5	151.7	151.9	154.4	0.9%
B. External Labor (Contractors & Consultants)	30.0	32.0	40.2	26.8	34.6	23.9	26.4	-11.8%
Subtotal Workforce Costs	160.3	163.6	179.7	182.3	186.3	175.8	180.8	-1.5%
C. Materials & Chemicals	16.2	16.8	16.2	14.9	16.3	16.5	15.1	-3.6%
D. Employee Expenses	3.9	4.2	5.7	4.9	5.7	3.6	4.6	-10.1%
E. Other	4.8	5.9	4.9	5.6	6.6	4.3	8.2	11.6%
Non-Outage Site Costs Total	185.2	190.6	206.4	207.6	215.0	200.2	208.7	-1.5%
Non-Site Costs Total								
F. Nuclear-related fees	31.9	34.6	31.5	35.2	36.9	37.5	39.2	3.2%
G. Security	26.7	27.2	27.8	29.0	30.8	33.3	33.4	4.2%
Non-Site Costs Total	58.6	61.8	59.3	64.2	67.7	70.7	72.6	3.7%
Total Non-Outage O&M	243.8	252.4	265.7	271.8	282.7	270.9	281.3	-0.2%

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Xcel Energy
Docket No.: E002/GR-15-826
Response To: Department of Commerce Information Request No. 1190
Requestor: Nancy Campbell
Date Received: May 11, 2016

Question:

Reference: Volume 6A Budget Documentation, Tab B Nuclear Generation p 5 & 11

Subject: Nuclear O&M Costs for 2012 to 2020

On an electronic spreadsheet, please provide the following:

(a) Actual Nuclear O&M for 2012 to 2015 for Non-Outage O&M costs, Outage O&M costs (include number of outages and numbers of days for each outage by year), and Total Nuclear O&M costs.

(b) Budgeted Nuclear O&M for 2012 to 2020 for Non-Outage O&M costs, Outage O&M costs (including number of outage and number day for each outage by year), and Total Nuclear O&M costs. (Department expects the 2017 and 2018 budget information to tie to Volume 6A Budget Documentation, Tab B Nuclear Generation p 5 and 11.)

(c) Test Year amounts for 2013, 2014, 2015, and 2016 to 2020 for Non-Outage O&M costs, Outage O&M costs (including number of outage and number day for each outage by year), and Total Nuclear O&M costs.

(d) Please explain differences between 2017 to 2020 Budget information and 2017 to 2020 Test Year amounts by year.

Response:

(a) Attachment A to this response provides the requested information for actual Nuclear O&M costs and outage count/duration for the years 2012-2015.

(b) Attachment B to this response provides the requested budget information for Nuclear O&M costs and outage count/duration for the years 2012-2020. Please note that we have not yet formalized the work schedule and duration for refueling outages in the years 2017-2020. While we are striving to improve outage efficiency in the future, as discussed in Mr. O'Connor's Direct Testimony in this case, our budget assumptions for 2017-2020 continue to carry forward the 2016 outage duration at this time.

(c) Attachment C to this response provides the requested test year information for Nuclear O&M costs for the rate case years 2013, 2014, and 2016. Please note that we did not provide a test year budget for 2015 in the 2014 rate case (filed in November 2013); consequently, Attachment C did not include test year amounts for 2015 Nuclear O&M. Attachment C provides the requested test year information for Nuclear O&M costs and outage count/duration for the years 2016-2018 as provided in this rate case. We did not provide in this rate case the test year amounts for 2017-2020 O&M for Nuclear, and consequently have no test year amounts for those years. However, in Attachment C we provide "plan year" amounts for 2017-2018 based on escalations from 2016 test year levels consistent with our multi-year proposal in the current case.

    In determining test year values for Attachment C, there were no changes to the budgeted outage count or duration items from budget values. Therefore Attachment C does not include outage count or duration please see Attachment B for those items.

(d) As discussed in part b) above, no test year amounts were provided in this rate case for Nuclear O&M for 2017-2020, so there are no differences from budget in those years.

    The 2017-2018 "plan year" amounts of Total Nuclear O&M included in Volume 4B, M5-1 of this rate case are slightly smaller than the 2017-2018 budget amounts of Total O&M included in Volume 6A (Budget Documentation), Tab B (Nuclear Generation). Total plan year O&M amounts for 2017 and 2018 are about $1.5 million (0.4%) and $0.9 million (0.2%) less than the corresponding budget amounts for those years, due to the independent calculation of 2017-2018 plan years through escalation of 2016 test year amounts, rather than being based on our internal budgets.

Witness:	Timothy J. O'Connor
Preparer:	Linda Erickson / Mary Pope
Title:	Sr. Director, Finance & Nuclear Controller / Senior Rate Analyst Controls Specialist / Fin. Consultant
Department:	Nuclear Finance / Revenue Requirements North
Telephone:	612-330-7862 / 612-330-6574
Date:	May 23, 2016

$ in millions

		2012 Actual	2013 Actual	2014 Actual	2015 Actual
Non-Outage O&M Costs	a	$ 243.8	$ 265.7	$ 282.7	$ 270.9
Outage Related O&M	b	$ 87.6	$ 113.6	$ 48.0	$ 92.7
Outage Deferral & Amortization, net	c	$ (29.5)	$ (44.1)	$ 40.6	$ (14.2)
Net Outage Related Costs	d = b+c	$ 58.0	$ 69.4	$ 88.6	$ 78.5
TOTAL Nuclear Related O&M Costs	**e = a + d**	**$ 301.9**	**$ 335.2**	**$ 371.2**	**$ 349.4**
Number of Outages		2	2	1	2
<u>Outage Duration (Days)</u>					
PI Unit 2/Spring 2012		98			
PI Unit 1/Fall 2012		71			
MT/Spring 2013			138		
PI Unit 2/Fall 2013			105		
PI Unit 1/Fall 2014				44	
MT/Spring 2015					48
PI Unit 2/Fall 2015					51

Northern States Power Company
NSPM Electric
$ in millions

Docket No. E002/GR-15-826
DOC Information Request No. 1190
Attachment B, Page 1 of 1

		2012 Budget	2013 Budget	2014 Budget	2015 Budget	2016 Budget	2017 Budget	2018 Budget	2019 Budget	2020 Budget
Non-Outage O&M Costs	a	$ 240.7	$ 241.3	$ 271.8	$ 268.7	$ 281.3	$ 285.7	$ 291.5	$ 293.7	$ 298.1
Outage Related O&M	b	$ 75.9	$ 91.9	$ 46.0	$ 83.6	$ 45.5	$ 87.3	$ 47.3	$ 86.4	$ 43.9
Outage Deferral & Amortization	c	$ (13.7)	$ (19.4)	$ 44.4	$ (5.5)	$ 24.2	$ (18.4)	$ 19.3	$ (18.4)	$ 23.3
Net Outage Related Costs	d = b+c	$ 62.3	$ 72.5	$ 90.4	$ 78.1	$ 69.7	$ 68.9	$ 66.6	$ 68.0	$ 67.3
TOTAL Nuclear Related O&M Costs	**e = a + d**	**$ 303.0**	**$ 313.8**	**$ 362.2**	**$ 346.8**	**$ 351.1**	**$ 354.6**	**$ 358.1**	**$ 361.7**	**$ 365.3**
Number of Outages		2	2	1	2	1	2	1	2	1
Outage Duration (Days)										
PI Unit 2/Spring 2012		35								
PI Unit 1/Fall 2012		45								
MT/Spring 2013			80							
PI Unit 2/Fall 2013			65							
PI Unit 1/Fall 2014				33						
MT/Spring 2015					35					
PI Unit 2/Fall 2015					45					
PI Unit 1/Fall 2016						45				
MT/Spring 2017							45			
PI Unit 2/Fall 2017							45			
PI Unit 1/Fall 2018								45		
MT/Spring 2019									45	
PI Unit 2/Fall 2019									45	
PI Unit 1/Fall 2020										45

Northern States Power Company
NSPM Electric
$ in millions

		2013 Test Year	2014 Test Year	2016 Test Year	2017 Plan Year	2018 Plan Year	*Per Attachment B* 2017 Budget	2018 Budget	2017 Plan / 2017 Budget	2018 Plan / 2018 Budget
Non-Outage O&M Costs	a	$ 252.4	$ 271.8	$ 281.3	$ 284.2	$ 290.7	$ 285.7	$ 291.5	-0.5%	-0.3%
Outage Related O&M	b	$ 91.9	$ 45.2	$ 45.5	$ 87.3	$ 47.3	$ 87.3	$ 47.3	0.0%	0.0%
Outage Deferral	c	$ (91.9)	$ (45.2)	$ (45.5)	$ (87.3)	$ (47.3)	$ (87.3)	$ (47.3)	0.0%	0.0%
Amortization	d	$ 74.5	$ 89.3	$ 69.7	$ 68.9	$ 66.6	$ 68.9	$ 66.6	0.0%	0.0%
Net Outage Related Costs	e = b+c+d	$ 74.5	$ 89.3	$ 69.7	$ 68.9	$ 66.6	$ 68.9	$ 66.6	0.0%	0.0%
TOTAL Nuclear Related O&M Costs	**f = a + e**	**$ 326.9**	**$ 361.1**	**$ 351.1**	**$ 353.1**	**$ 357.3**	**$ 354.6**	**$ 358.1**	**-0.4%**	**-0.2%**
				Vol. 6A, Tab B, page 5			Vol. 6A, Tab B, page 5	Vol. 6A, Tab B, page 5		
Test Year Adjustments	g	$ (1.4)	$ (1.0)	$ (3.8)	$ -	$ -	$ (3.0)	$ (2.4)		
Adjustment Description		Nuclear Fees	Nuclear Fees	AIP and Retention	In escalation	In escalation	AIP and Retention	AIP and Retention		
Total Nuclear Related O&M	**h = f + g**	**$ 325.5**	**$ 360.1**	**$ 347.3**	**$ 353.1**	**$ 357.3**	**$ 351.6**	**$ 355.8**	**0.4%**	**0.4%**
Other Business Unit O&M in Nuclear FERC Accounts				$ 40.2	$ 40.8	$ 41.7	$ 40.3	$ 40.9	1.0%	2.1%
Total NSPM O&M in Nuclear FERC Accounts				**$ 387.5**	**$ 393.9**	**$ 399.0**	**$ 392.0**	**$ 396.6**	**0.5%**	**0.6%**
Minnesota Electric Jurisdiction O&M in Nuclear FERC Accounts				$ 338.5	$ 344.0	$ 348.7	$ 342.4	$ 346.4	0.5%	0.7%
				Volume 4B, M5-1	Volume 4B, M5-1	lume 4B, M5-1				
Docket Number:		E002/GR-12-961	E002/GR-13-868	E002/GR-15-826	E002/GR-15-826	E002/GR-15-826	E002/GR-15-826	E002/GR-15-826		
Testimony References:		O'Donnor Direct Pages 6-7 Table 2	O'Donnor Direct Page 82 Table 9	O'Donnor Direct Page 132 Table 7						
			O'Donnor Direct Schedule 16 Att. C	O'Donnor Direct Page 178 Table 13						

Notes:
All data reflects Total NSPM Electric except last line labeled "Minnesota Electric Jurisdiction O&M in Nuclear FERC Accounts".
MN Jurisdiction amounts are NOT net of Interchange Billings to NSPW

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

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

Xcel Energy			
Docket No.:	E002/GR-15-826		
Response To:	MN Department of Commerce	Information Request No.	1171
Requestor:	Nancy Campbell, Dale Lusti, Angela Byrne		
Date Received:	May 5, 2016		

Question:
Reference: April 29, 2016 Compliance Filing in Docket No. E002/AI-14-759

Subject: Transco Allocations

a) Xcel provided in its April 29, 2016 Compliance Filing, a trade secret amount for 2015 Transco labor costs which will be returned to customers in current rate case. Please show how this amount is being given back to ratepayers in the current rate case or alternatively provide the adjustment for all test years to support 2015 Transco labor be excluded from the Minnesota Jurisdiction for both NSPM costs and Service Company costs.

b) Please support why actual historical costs, especially the rolled up total amount in this compliance filing are considered trade secret?

c) Please provide support for allocations or other cost information in determining the Minnesota Jurisdictional amount which appears small compared to the total Transco costs. DOC notes Schedule 4 of Direct Testimony of Adam Dietenberger shows majority of cost assigned to NSPM is around 40 to 45%, so why is the Transco allocation to MN for labor support from NSP-M and Service Company employees so small and significantly less than 40 to 45%?

d) Please support the expected level of Transco costs expected in 2016 - 2020, including how many employees and hours NSPM and Service will work on Transco issues? At this time, has the Company submitted any bids for transmission projects?

Response:

a) The Company proposes to make an adjustment to the 2014 Transco labor cost amortization in our Rebuttal Cost of Service Study to return to customers the 2015 Transco labor amount identified in its April 29, 2016 Transco Compliance filing. The original 2014 Transco labor cost amortization detail was provided in Volume 4B, Tab VIII. Adjustments, Section A34 Transco Costs.

b) Attachment A to the Company's April 29, 2016 Compliance Filing in Docket No. E002/AI-14-759 contains actual cost information that is competitively sensitive and that the Company maintains as trade secret information pursuant to Minn. Stat. §13.37. Competing transmission companies may be able to use knowledge of the costs incurred (or expected to be incurred) by Xcel Energy Transcos to gain a competitive advantage in future Regional Transmission Organization competitive solicitation processes. In this way, disclosure of these amounts could harm Xcel Energy, Xcel Energy Transmission Development Company, LLC, and/or Xcel Energy Southwest Transmission Company, LLC. Upon further review, however, the Company does not believe that the rolled up totals identified in both Attachment A and the cover letter properly qualify as trade secret. We filed a revised cover letter and Attachment A in Docket No. E002/AI-14-759 on May 17, 2016, in which only the subtotals were redacted.

c) The purpose of the Company's April 29, 2016 Transco Compliance filing was to quantify the Transco related labor costs included in the 2014 Test Year Plus 2015 Step (2015 Test Year) as approved in Docket No. E002/GR-13-868. Not all costs incurred by Transco were included in the 2015 Test Year. For example, most Transco-related legal service costs were for external resources incremental to costs in the 2015 Budget and 2015 Test Year. Any changes to the cost of those external resources would be included in total Xcel Transco expenses, but would not be allocated to the Minnesota Jurisdiction because they were not part of the original 2015 Test Year. In addition, expenses in Transmission business units outside the NSPM service territory (i.e. Southwest Power Pool or SPS) were not included in either the original 2015 NSPM Budget or 2015 Test Year, and changes to expenses in those business units would not be included in the Minnesota Jurisdictional allocation.

   Attachment A with this response contains 2015 actual Transco expenses by business unit and cost type, and the Minnesota Jurisdictional allocations. Please note, for consistent comparison to the 2015 Test Year in Docket No.

E002/GR-13-868, test year jurisdictional allocation factors were applied to the 2015 actual Transco expenses.

d) The Transco budget for 2016 – 2020 was developed on the basis of the expected activity by the Service Company departments on behalf of the Transco. Because the competitive opportunities are not certain, flexibility was established with budgeted internal and external labor resources. Transmission assumed six full-time Service Company employees from three departments would be designated to Transco efforts, equating to 12,480 hours. General Counsel assumed 10% of one full-time person from Federal Regulatory Affairs and 50% of one full-time employee from Legal Services would be designated to Transco efforts, equating to 1,248 hours. Finance assumed 15% of one full-time employee from Technical Accounting and 10% of one full-time employee from Treasury would be designated to Transco efforts, equating to 520 hours. The labor dollars associated with these labor hours were included in the 2016 Budget and direct charged from the Service Company to the Transco budget. The 2016 Transco budget is $2,278,049, with future years' budgets remaining constant. The budget drivers include **[TRADE SECRET BEGINS TRADE SECRET ENDS]** in Transmission internal loaded labor, **[TRADE SECRET BEGINS TRADE SECRET ENDS]** in Transmission external consultant labor, **[TRADE SECRET BEGINS TRADE SECRET ENDS]**in regulatory fees for bid submission costs established by MISO, **[TRADE SECRET BEGINS TRADE SECRET ENDS]**in employee expenses to enable Transmission employees to engage in business development and bid support, **[TRADE SECRET BEGINS TRADE SECRET ENDS]** in internal legal labor, **[TRADE SECRET BEGINS TRADE SECRET ENDS]** in external legal consulting, and **[TRADE SECRET BEGINS TRADE SECRET ENDS]** in Service Company labor from Financial Operations. At this time, Transco has submitted one bid in SPP.

This response, including Attachment A to this response, contains actual cost information that is competitively sensitive and that the Company maintains as trade secret information pursuant to Minn. Stat. §13.37. Competing transmission companies may be able to use knowledge of the costs incurred (or expected to be incurred) by Xcel Energy Transcos to gain a competitive advantage in future Regional Transmission Organization competitive solicitation processes. In this way, disclosure of these amounts could harm Xcel Energy, Xcel Energy Transmission Development Company, LLC, and/or Xcel Energy Southwest Transmission Company, LLC.

Witness:	Adam R. Dietenberger and Ian R. Benson
Preparer:	Mary Pope / Laurie Wold
Title:	Sr. Rate Analyst / Manager, Budgeting & Reporting
Department:	Revenue Requirements North / Transmission Finance
Telephone:	612-330-6574 / 612-330-5510
Date:	May 18, 2016

2015 Transco Related Expenses allocated to NSPM Electric and MN Juris Electric USING 2014 BUDGET ALLOCATORS

87.6138% MN Electric Jur Transmission Allocator

Sum of Amount

Bus Unit Cd	Bus Unit Desc	Obj Acct	Acct Description	Grand Total	NSPM Electric Allocation	Estimated NSPM Electric	MN Juris Allocator	Estimated 2015 MN Jurisdiction	Business Area
				[TRADE SECRET BEGINS					
260007	OS Senior VP Operations	711142	711142 Productive Labor						
		711144	711144 Reg Labor Loading-Pension&401K						
		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		764000	764000 Payroll Taxes						
260007 Total									**Financial Operations**
389000	CF Utility Accounting	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
		711144	711144 Reg Labor Loading-Pension&401K						
		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		764000	764000 Payroll Taxes						
389000 Total									**Financial Operations**
500060	Real Estate Services	723300	723300 Lease Costs						
500060 Total									**Other**
500061	Leases Services Co	723300	723300 Lease Costs						
500061 Total									**Other**
500070	Facility Services North	723300	723300 Lease Costs						
500070 Total									**Other**
500075	Facility Services South	723300	723300 Lease Costs						
500075 Total									**Other**
500123	Shared Asset Cost - XLS	723300	723300 Lease Costs						
500123 Total									**Other**
500140	Project/Tenant Services	723300	723300 Lease Costs						
500140 Total									**Other**
500141	Corporate Mail Service	723300	723300 Lease Costs						
500141 Total									**Other**
500142	Facilities Support	723300	723300 Lease Costs						
500142 Total									**Other**
500143	Print Services	723300	723300 Lease Costs						
500143 Total									**Other**
500150	Administrative Services	723300	723300 Lease Costs						
500150 Total									**Other**
500155	Property Services Mgmt	723300	723300 Lease Costs						
500155 Total									**Other**
500200	SC Sourcing Alloc P	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
		711144	711144 Reg Labor Loading-Pension&401K						
No expenses related to		711145	711145 Reg Labor Loading-Insurance						
Transco in 2014 TY		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		764000	764000 Payroll Taxes						
500200 Total									**Financial Operations**
500201	SC Maj Cap & Comm Prj Sourcing	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
		711144	711144 Reg Labor Loading-Pension&401K						
		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
None of 2014 Budget		711160	711160 Reg Labor Load-Incentive						
expenses assigned to NSPM		712110	712110 Contract Labor						
		713000	713000 Consulting/Prof Svcs-Other						
		721020	721020 EE Exp Mileage						
		721040	721040 EE Exp Meals/Incl.Non-EE's						

2015 Transco Related Expenses allocated to NSPM Electric and MN Juris Electric USING 2014 BUDGET ALLOCATORS

MN Electric Jur
87.6138% Transmission Allocator

Sum of Amount

Bus Unit Cd	Bus Unit Desc	Obj Acct	Acct Description	Grand Total	NSPM Electric Allocation	Estimated NSPM Electric	MN Juris Allocator	Estimated 2015 MN Jurisdiction	Business Area
		764000	764000 Payroll Taxes						
500201 Total									**Financial Operations**
601200	CF Capital Asset Acct	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
		711144	711144 Reg Labor Loading-Pension&401K						
		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		764000	764000 Payroll Taxes						
601200 Total									**Financial Operations**
601300	CF Corporate Acct	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
		711144	711144 Reg Labor Loading-Pension&401K						
		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		764000	764000 Payroll Taxes						
601300 Total									**Financial Operations**
601400	CF Financial Rptg & Tech Acctg	711145	711145 Reg Labor Loading-Insurance						
601400 Total									**Financial Operations**
601500	CF Office of the Controller	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
No expenses related to		711144	711144 Reg Labor Loading-Pension&401K						
Transco in 2014 TY		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		764000	764000 Payroll Taxes						
601500 Total									**Financial Operations**
601850	CF Transmission Finance	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
		711144	711144 Reg Labor Loading-Pension&401K						
		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		764000	764000 Payroll Taxes						
601850 Total									**Financial Operations**
601900	CF Tax Services	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
		711144	711144 Reg Labor Loading-Pension&401K						
		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		723400	723400 Postage						
		764000	764000 Payroll Taxes						
601900 Total									**Financial Operations**
605500	Assistant Treasurer	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
		711144	711144 Reg Labor Loading-Pension&401K						
		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		764000	764000 Payroll Taxes						
605500 Total									**Financial Operations**
620000	GC VP General Counsel	711142	711142 Productive Labor						
		711144	711144 Reg Labor Loading-Pension&401K						
		711145	711145 Reg Labor Loading-Insurance						

2015 Transco Related Expenses allocated to NSPM Electric and MN Juris Electric USING 2014 BUDGET ALLOCATORS

MN Electric Jur
87.6138% Transmission Allocator

Sum of Amount

Bus Unit Cd	Bus Unit Desc	Obj Acct	Acct Description	Grand Total	NSPM Electric Allocation	Estimated NSPM Electric	MN Juris Allocator	Estimated 2015 MN Jurisdiction	Business Area
		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		764000	764000 Payroll Taxes						
620000 Total									**Financial Operations**
620100	GC Legal Services	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
		711144	711144 Reg Labor Loading-Pension&401K						
		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		713100	713100 Consulting/Prof Svcs-Legal						
		713120	713120 Consult/Legal - Regulatory						
		721005	721005 EE Exp Airfare						
		721010	721010 EE Exp Car Rental						
		721015	721015 EE Exp Taxi/Bus						
		721020	721020 EE Exp Mileage						
		721030	721030 EE Exp Hotel						
		721035	721035 EE Exp Meals/EE's						
		721040	721040 EE Exp Meals/Incl.Non-EE's						
		721045	721045 EE Exp Parking						
		723031	723031 Electric Use Costs						
		723400	723400 Postage						
		723810	723810 Professional Association Dues						
		764000	764000 Payroll Taxes						
620100 Total									**Legal Services**
622000	GC Federal Regulatory Affairs	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
		711144	711144 Reg Labor Loading-Pension&401K						
		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		721005	721005 EE Exp Airfare						
		721015	721015 EE Exp Taxi/Bus						
		721020	721020 EE Exp Mileage						
		721035	721035 EE Exp Meals/EE's						
		721045	721045 EE Exp Parking						
		721060	721060 EE Exp Other						
		764000	764000 Payroll Taxes						
622000 Total									**Legal Services**
622500	Revenue Requirements	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
		711144	711144 Reg Labor Loading-Pension&401K						
		711145	711145 Reg Labor Loading-Insurance						
No expenses related to		711149	711149 Reg Labor Loading-Inj & Dam						
Transco in 2014 TY		711160	711160 Reg Labor Load-Incentive						
		713000	713000 Consulting/Prof Svcs-Other						
		723400	723400 Postage						
		764000	764000 Payroll Taxes						
622500 Total									**Financial Operations**
622550	Revenue Requirements North	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
No expenses related to		711144	711144 Reg Labor Loading-Pension&401K						
Transco in 2014 TY		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		764000	764000 Payroll Taxes						

2015 Transco Related Expenses allocated to NSPM Electric and MN Juris Electric USING 2014 BUDGET ALLOCATORS

87.6138% MN Electric Jur Transmission Allocator

Sum of Amount

Bus Unit Cd	Bus Unit Desc	Obj Acct	Acct Description	Grand Total	NSPM Electric Allocation	Estimated NSPM Electric	MN Juris Allocator	Estimated 2015 MN Jurisdiction	Business Area
622550 Total									**Financial Operations**
624000	Revenue Requirements South	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
		711144	711144 Reg Labor Loading-Pension&401K						
		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		721005	721005 EE Exp Airfare						
		721015	721015 EE Exp Taxi/Bus						
		721020	721020 EE Exp Mileage						
		721030	721030 EE Exp Hotel						
		721035	721035 EE Exp Meals/EE's						
		721045	721045 EE Exp Parking						
		721060	721060 EE Exp Other						
		764000	764000 Payroll Taxes						
624000 Total									**Financial Operations**
640008	Corporate Development	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
No expenses related to		711144	711144 Reg Labor Loading-Pension&401K						
Transco in 2014 TY		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		764000	764000 Payroll Taxes						
640008 Total									**Other**
650000	Contractor Safety	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
No expenses related to		711144	711144 Reg Labor Loading-Pension&401K						
Transco in 2014 TY		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		764000	764000 Payroll Taxes						
650000 Total									**Other**
801334	XE West Trans Co	723821	723821 Electric Util Assoc Dues						
No expenses related to Transco in 2014 TY		723860	723860 Bank Charges						
801334 Total									**Transmission**
832700	Transmission Investment	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
		711144	711144 Reg Labor Loading-Pension&401K						
		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
No expenses related to		712110	712110 Contract Labor						
Transco in 2014 TY		713000	713000 Consulting/Prof Svcs-Other						
		713050	713050 Contract LT Outside Vendor						
		721005	721005 EE Exp Airfare						
THIS BU doesn't exist in 2014TY		721010	721010 EE Exp Car Rental						
		721015	721015 EE Exp Taxi/Bus						
		721020	721020 EE Exp Mileage						
		721030	721030 EE Exp Hotel						
		721035	721035 EE Exp Meals/EE's						
		721040	721040 EE Exp Meals/Incl.Non-EE's						
		721045	721045 EE Exp Parking						
		721060	721060 EE Exp Other						
		721750	721750 Recog - Employee Engagement						
		723855	723855 Other Deductions						
		764000	764000 Payroll Taxes						

2015 Transco Related Expenses allocated to NSPM Electric and MN Juris Electric USING 2014 BUDGET ALLOCATORS

MN Electric Jur
87.6138% Transmission Allocator

Sum of Amount

Bus Unit Cd	Bus Unit Desc	Obj Acct	Acct Description	Grand Total	NSPM Electric Allocation	Estimated NSPM Electric	MN Juris Allocator	Estimated 2015 MN Jurisdiction	Business Area
832700 Total									**Transmission**
840800	Transm Engineering South XS	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
No expenses related to		711144	711144 Reg Labor Loading-Pension&401K						
Transco in 2014 TY		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		764000	764000 Payroll Taxes						
840800 Total									**Transmission**
850400	Transm Captl Project Mgmt XS	712110	712110 Contract Labor						
850400 Total									**Transmission**
850405	Project Mgmt - North (XS)	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
No expenses related to		711144	711144 Reg Labor Loading-Pension&401K						
Transco in 2014 TY		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		721005	721005 EE Exp Airfare						
		764000	764000 Payroll Taxes						
850405 Total									**Transmission**
850409	Project Controls (XS)	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
		711144	711144 Reg Labor Loading-Pension&401K						
No expenses related to		711145	711145 Reg Labor Loading-Insurance						
Transco in 2014 TY		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		764000	764000 Payroll Taxes						
850409 Total									**Transmission**
850412	Dir Trans Planning XS	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
		711144	711144 Reg Labor Loading-Pension&401K						
		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		721005	721005 EE Exp Airfare						
		721035	721035 EE Exp Meals/EE's						
		721040	721040 EE Exp Meals/Incl.Non-EE's						
		764000	764000 Payroll Taxes						
850412 Total									**Transmission**
855600	Transm Regional Planning (XS)	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
		711144	711144 Reg Labor Loading-Pension&401K						
		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		764000	764000 Payroll Taxes						
855600 Total									**Transmission**
855603	Regional Transmission Policy	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
		711144	711144 Reg Labor Loading-Pension&401K						
		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		764000	764000 Payroll Taxes						
855603 Total									**Transmission**
855695	TRANSM PLANNING NORTH XES	711142	711142 Productive Labor						

2015 Transco Related Expenses allocated to NSPM Electric and MN Juris Electric USING 2014 BUDGET ALLOCATORS

87.6138% MN Electric Jur Transmission Allocator

Sum of Amount

Bus Unit Cd	Bus Unit Desc	Obj Acct	Acct Description	Grand Total	NSPM Electric Allocation	Estimated NSPM Electric	MN Juris Allocator	Estimated 2015 MN Jurisdiction	Business Area
		711143	711143 Reg Labor Loading-NonProductiv						
No expenses related to		711144	711144 Reg Labor Loading-Pension&401K						
Transco in 2014 TY		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		764000	764000 Payroll Taxes						
855695 Total									**Transmission**
857000	Siting & Land Rights No. (XS)	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
		711144	711144 Reg Labor Loading-Pension&401K						
		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		713000	713000 Consulting/Prof Svcs-Other						
		723895	723895 License Fees & Permits						
		764000	764000 Payroll Taxes						
857000 Total									**Transmission**
857002	Siting & Land Rights So. (XS)	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
		711144	711144 Reg Labor Loading-Pension&401K						
		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		721030	721030 EE Exp Hotel						
		721035	721035 EE Exp Meals/EE's						
		764000	764000 Payroll Taxes						
857002 Total									**Transmission**
857200	Transm Eng South O&M XS	713000	713000 Consulting/Prof Svcs-Other						
857200 Total									**Transmission**
857304	Siting & Land Rights (PSCo)	723895	723895 License Fees & Permits						
857304 Total									**Transmission**
857400	Transm Engineer North O&M XS	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
		711144	711144 Reg Labor Loading-Pension&401K						
No expenses related to		711145	711145 Reg Labor Loading-Insurance						
Transco in 2014 TY		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		711190	711190 Overtime						
		712110	712110 Contract Labor						
		721020	721020 EE Exp Mileage						
		764000	764000 Payroll Taxes						
857400 Total									**Transmission**
857800	Siting&Lnd Rghts Mpls(NSP-MN)	713000	713000 Consulting/Prof Svcs-Other						
857800 Total									**Transmission**

2015 Transco Related Expenses allocated to NSPM Electric and MN Juris Electric USING 2014 BUDGET ALLOCATORS

MN Electric Jur
87.6138% Transmission Allocator

Sum of Amount

Bus Unit Cd	Bus Unit Desc	Obj Acct	Acct Description	Grand Total	NSPM Electric Allocation	Estimated NSPM Electric	MN Juris Allocator	Estimated 2015 MN Jurisdiction	Business Area
859400	Transm Eng & Design South Misc	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
		711144	711144 Reg Labor Loading-Pension&401K						
		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		721005	721005 EE Exp Airfare						
		721030	721030 EE Exp Hotel						
		721035	721035 EE Exp Meals/EE's						
		764000	764000 Payroll Taxes						
859400 Total									**Transmission**
865552	Transm Const SPS ET560	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
		711144	711144 Reg Labor Loading-Pension&401K						
		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
SPS OpCo Direct assigned		711160	711160 Reg Labor Load-Incentive						
		764000	764000 Payroll Taxes						
865552 Total									**Transmission**
880000	Transmission & Subs VP (XS)	711142	711142 Productive Labor						
		711144	711144 Reg Labor Loading-Pension&401K						
		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		764000	764000 Payroll Taxes						
880000 Total									**Transmission**
880001	Transmission PTT	721005	721005 EE Exp Airfare						
		721045	721045 EE Exp Parking						
880001 Total									**Transmission**
881114	Strategic Transm Initiatives	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
		711144	711144 Reg Labor Loading-Pension&401K						
		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		721005	721005 EE Exp Airfare						
		721010	721010 EE Exp Car Rental						
		721015	721015 EE Exp Taxi/Bus						
		721020	721020 EE Exp Mileage						
		721030	721030 EE Exp Hotel						
		721035	721035 EE Exp Meals/EE's						
		721040	721040 EE Exp Meals/Incl.Non-EE's						
		721045	721045 EE Exp Parking						
		723855	723855 Other Deductions						
		764000	764000 Payroll Taxes						
881114 Total									**Transmission**
890812	Vegetation Mgmt SPS 588	711142	711142 Productive Labor						
		711143	711143 Reg Labor Loading-NonProductiv						
		711144	711144 Reg Labor Loading-Pension&401K						
SPS OpCo Direct assigned		711145	711145 Reg Labor Loading-Insurance						
		711149	711149 Reg Labor Loading-Inj & Dam						
		711160	711160 Reg Labor Load-Incentive						
		764000	764000 Payroll Taxes						
890812 Total									**Other**

TRADE SECRET ENDS]

2015 Transco Related Expenses allocated to NSPM Electric and MN Juris Electric USING 2014 BUDGET ALLOCATORS

									MN Electric Jur
								87.6138%	Transmission Allocator
Sum of Amount									
Bus Unit Cd	**Bus Unit Desc**	**Obj Acct**	**Acct Description**	**Grand Total**	**NSPM Electric Allocation**	**Estimated NSPM Electric**	**MN Juris Allocator**	**Estimated 2015 MN Jurisdiction**	Business Area
Grand Total				**2,009,333**		**207,701**		**181,975**	
								2015	
				689,163		**104,103**		**91,209**	Transmission
				1,099,243		**58,250**		**51,035**	Legal Services
				167,923		**40,743**		**35,696**	Financial Operations
				53,004		**4,605**		**4,035**	Other
				2,009,333		**207,701**		**181,975**	Total