414 Nicollet Mall
Minneapolis, Minnesota 55401

October 7, 2014

The Honorable Jeanne M. Cochran
Administrative Law Judge
Office of Administrative Hearings
P.O. Box 64620
St. Paul, MN 55164-0620

RE: XCEL ENERGY'S APPLICATION FOR AUTHORITY TO INCREASE RATES FOR ELECTRIC SERVICE IN THE STATE OF MINNESOTA
OAH DOCKET NO. 68-2500-31182
DOCKET NO. E002/GR-13-868

Dear Judge Cochran:

On September 10, 2014, Xcel Energy submitted the Issues List filing in accordance with the First Pre-Hearing Order dated February 14, 2014. Comments on the filed Issues List were submitted by Parties on September 30, 2014. We now provide an updated and final version of the complete Issues List which reflects the feedback received from Parties. I note that the Company has not reviewed the initial briefs, submitted on September 23, in order to identify possible additional changes to Parties respective positions on issues. Rather, we assumed that Parties' comments on the initial Issues List would reflect any possible revisions to their positions.

In accordance with the First Pre-Hearing Order and the guidance you prescribed during the July 17, 2014 pre-hearing conference, the enclosed materials are intended to provide a description and summary of the issues, positions and financial adjustments proposed by parties with citations to the record developed for Xcel Energy's electric rate case in the above described dockets.

This filing consists of the following documents:

- Financial Adjustment Summary (2014 and 2015 Step)
- Rate Base and Income Statement Bridge Schedules (Xcel Energy and Department for 2014 and 2015 Step)
- Final Issues List
- Final Issues List – Redline Version

The only change made to the Financial Adjustment Summary4 was a correction to remove the PI EPU abandoned plant balance from the Department's 2014 rate base. This change is reflected in the quantification of the Department's recommended reduction in ROE. We note that we worked with the Department in regards to this correction and have not made any other changes to the Financial Adjustment Summary that was submitted on September 10, 2014.

Please contact me with any questions regarding this filing at (612) 215-4663 or at Aakash.Chandarana@xcelenergy.com or Gail Baranko at (612) 330-6935 or at gail.a.baranko@xcelenergy.com.

Respectfully Submitted,

/s/

AAKASH H. CHANDARANA
LEAD REGULATORY ATTORNEY - NORTH

Enclosures

cc: Service List

Certificate of Service

I, Jada R. Calhoun, hereby certify that I have this day served copies or summaries 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 by e-mail; or

xx electronic filing.

OAH Docket No. 68-2500-31182

MPUC Docket No. E002/GR-13-868

Dated this 7th day of October 2014

/s/
____
Jada R. Calhoun

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Jorge	Alonso	jorge.alonso@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
Alison C	Archer	alison.c.archer@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 5 Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
Andrew	Bahn	Andrew.Bahn@state.mn.us	Public Utilities Commission	121 7th Place E., Suite 350 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
Ryan	Barlow	Ryan.Barlow@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Bremer Tower, Suite 1400 St. Paul, Minnesota 55101	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
James	Canaday	james.canaday@ag.state.mn.us	Office of the Attorney General-RUD	Suite 1400 445 Minnesota St. St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
Aakash	Chandarana	Aakash.Chandara@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 5 Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
Jeanne	Cochran	Jeanne.Cochran@state.mn.us	Office of Administrative Hearings	P.O. Box 64620 St. Paul, MN 55164-0620	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_13-868_Official CC Service List
Jerry	Dasinger	jerry.dasinger@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.	414 Nicollet Mall, Fifth Floor Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
Ian	Dobson	ian.dobson@ag.state.mn.us	Office of the Attorney General-RUD	Antitrust and Utilities Division 445 Minnesota Street, 1400 BRM Tower St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
Benjamin	Gerber	bgerber@mnchamber.com	Minnesota Chamber of Commerce	400 Robert Street North Suite 1500 St. Paul, Minnesota 55101	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
Robert	Harding	robert.harding@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law	2265 Roswell Road Suite 100 Marietta, GA 30062	Electronic Service	No	OFF_SL_13-868_Official CC Service List
Linda	Jensen	linda.s.jensen@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota Street St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
Sarah	Johnson Phillips	sjphillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_13-868_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Clark	Kaml	clark.kaml@state.mn.us	Public Utilities Commission	121 E 7th Place, Suite 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
Mara	Koeller	mara.n.koeller@xcelenergy.com	Xcel Energy	414 Nicollet Mall 5th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_13-868_Official CC Service List
Ganesh	Krishnan	ganesh.krishnan@state.mn.us	Public Utilities Commission	Suite 350121 7th Place East St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	1500 Wells Fargo Plaza 7900 Xerxes Ave S Bloomington, MN 55431	Electronic Service	No	OFF_SL_13-868_Official CC Service List
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
Susan	Mackenzie	susan.mackenzie@state.mn.us	Public Utilities Commission	Suite 350121 7th Place East St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
Peter	Madsen	peter.madsen@ag.state.mn.us	Office of the Attorney General-DOC	Bremer Tower, Suite 1800 445 Minnesota Street St. Paul, Minnesota 55101	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_13-868_Official CC Service List
Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	414 Nicollet Mall 7th Floor Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_13-868_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Andrew	Moratzka	apmoratzka@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
Dorothy	Morrissey	dorothy.morrissey@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	Ste 122 9100 W Bloomington Frwy Bloomington, MN 55431	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
Sean	Stalpes	sean.stalpes@state.mn.us	Public Utilities Commission	121 E. 7th Place, Suite 350 Saint Paul, MN 55101-2147	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
James M.	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	470 U.S. Bank Plaza 200 South Sixth Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_13-868_Official CC Service List
SaGonna	Thompson	Regulatory.Records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
Kari L	Valley	kari.l.valley@xcelenergy.com	Xcel Energy Service Inc.	414 Nicollet Mall FL 5 Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_13-868_Official CC Service List
Samantha	Williams	swilliams@nrdc.org	Natural Resources Defense Council	20 N. Wacker Drive Ste 1600 Chicago, IL 60606	Electronic Service	No	OFF_SL_13-868_Official CC Service List

Final Issue Summary of Revenue Requirements - October 7, 2014
MPUC Docket No. E002/GR-13-868 / OAH Docket No. 68-2500-31182
2014 MN Electric Rate Case and 2015 Step
$ millions

Issue #	Issue Title	Notes	XCEL	DOC	OAG	MCC	XLI	ICI
	2014 CASE AS FILED		$192.710	$192.710				
	DISPUTED ITEMS							
1	Return on Equity (ROE)	[1], [3]	-	(36.132)				
2	Monticello EPU - Used and Useful In-Service Date		(12.227)	(31.286)		(12.227)	(28.551)	
3	Prairie Island Cancelled EPU Project		(4.865)	(4.865)	(4.398)	(5.475)		(8.595)
4	Qualified Pension discount rate		-	(1.770)				
5	Qualified Pension 2008 market loss		-	(6.174)				
6	Retiree Medical Expenses (FAS 106)		-	(1.592)				
7	Paid Leave / Total Labor		-	(5.600)				
8	Rate Case and Monticello EPU Prudence expenses		-	(0.418)				
11	In-Service Dates for Capital Projects		-	(2.184)				
13	Sales Forecast	[2]	(15.755)	(43.228)		(27.200)		
63	CWIP / AFUDC recovery	[1]	-		(3.800)			
64	Nuclear Refueling Outage Costs		-		(4.600)			
65	Aviation		-		(0.920)			
75	Nuclear Theoretical Reserve		-	-	-		(25.700)	
76	Black Dog Outage		-				(1.838)	
79	MYRP in General							81.063
	RESOLVED ITEMS							
12	Cost of Debt	[3]	(1.330)					
14	Property Taxes	[2]	(9.000)	(9.000)				
15	Emission Control Chemical Costs		(2.265)	(2.265)				
16	Insurance - Surplus distributions		(1.662)	(1.662)				
18	Qualified Pension - measurement date		1.011	1.011				
19	Retiree Medical Expenses (FAS 106) measurement date		(0.667)	(0.667)				
20	Non-Qualified Pension - restoration plan		(0.704)	(0.704)				
21	Post-Employement Benefits (FAS 112) measurement date		(0.421)	(0.421)				
22	Active Health Care		(1.081)	(1.081)				
23	Nuclear Retention Program		(0.516)	(0.516)				
24	Customer Care O&M Expenses		(0.503)	(0.503)				
25	Nuclear Fees		(1.000)	(1.000)				
26	Investor Relations Costs		(0.078)	(0.078)				
38	Hollydale Project		(0.043)	(0.043)				
39	PI EPU/LCM Split		(0.168)	(0.168)				
40	Xcel Energy Foundation Cost Correction		(0.115)	(0.115)				
41	Big Stone-Brookings Correction		(0.147)	(0.147)				
42	Bargaining Unit Wage Increase		(0.405)	(0.405)				
43	Theoretical Reserve correction - Intangible Plant		0.028	0.028				
44	NOL Correction		(0.367)	(0.367)				
45	Monticello Cyber Security		-	-				
46	Alliant Wholesale Billing Revenues		-	-				
47	Cost of Capital / Interest and Tax Calculation Sync	[3]	(0.066)	3.654				
48	NOL Impact	[3]	0.919	(0.000)				
49	Cash Working Capital Impact	[3]	0.875	0.948				
	REVENUE IMPACT OF ADJUSTED CASE - 2014	[5]	$142.156	$45.958				

[1] AARP, CEI, and/or CG disputed but did not quantify this issue.
[2] Subject to true-up
[3] To be updated based on Commission decision during compliance for setting final rates
[4] To be updated during compliance based on actual capital-related revenue requirement
[5] Xcel and DOC are the only parties that provided a fully quantified position

Final Issue Summary of Revenue Requirements - October 7, 2014
MPUC Docket No. E002/GR-13-868 / OAH Docket No. 68-2500-31182
2014 MN Electric Rate Case and 2015 Step
$ millions

Issue #	Issue Title	Notes	XCEL	DOC	OAG	MCC	XLI	ICI
	2015 STEP AS FILED		$98.533	$98.533				
	DISPUTED ITEMS							
1	ROE	[1], [3]		(2.817)				
2	Monticello EPU - Used and Useful In-Service Date		11.680	18.901		11.680	26.406	
9	Theoretical Reserve Rate Moderation		-	(12.633)				
10	Depreciation and Plant Retirements - Passage of Time		-	(18.064)				
11	In-Service Dates for Capital Projects		-	(2.054)				
13	Sales Forecast		-	-				
30	Pleasant Valley and Border Winds		(11.093)	(11.093)	(16.765)	(23.177)		
35	Cancelled or Postponed Capital Projects	[4]	-	-				
63	CWIP / AFUDC recovery	[1]	-		0.900			
79	MYRP in General							(98.533)
	RESOLVED ITEMS							
12	Cost of Debt	[3]	2.034	-				
27	Nuclear Refueling Outage		-	-				
28	General Ledger System		-	-				
29	Prairie Island Site Administration Building		-	-				
32	Property Taxes		(3.309)	(3.309)				
33	Emissions Control Chemical Costs		(1.580)	(1.580)				
34	Rate Moderation - DOE Settlement Funds		10.103	-				
47	Cost of Capital / Interest Sync	[3]	(0.070)	1.097				
48	NOL Impact	[3]	0.279	-				
49	Cash Working Capital Impact	[3]	0.286	(0.483)				
	REVENUE IMPACT OF ADJUSTED CASE - 2015	[5]	$106.864	$66.499				
	COMBINED 2014 AND 2015 STEP	[5]	$249.020	$112.456				

[1] AARP, CEI, and/or CG disputed but did not quantify this issue.
[2] Subject to true-up
[3] To be updated based on Commission decision during compliance for setting final rates
[4] To be updated during compliance based on actual capital-related revenue requirement
[5] Xcel and DOC are the only parties that provided a fully quantified position

Northern States Power Company

RATE BASE SCHEDULES
RATE BASE ADJUSTMENT SCHEDULES
Xcel Energy Position
2014 Test Year vs 2014 Test Year Hearing Position

($000's)

Line No.	Description	Proposed 2014 Test Year	Monti MCC	PI Cancelled Project	PI EPU Debt Return	Sales Forecast	Property Taxes	Emissions Chemicals	Surplus Insurance	Qual Pen Measurement Date	FAS 106	Non Qual Pen Measurement Date	FAS 112	Active Health Care	Nuclear Retention Program
	Work Paper Reference		2	3	3	13	14	15	16	18	19	20	21	22	23
	Electric Plant as Booked														
1	Production	$8,178,489	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	Transmission	$2,002,245													
3	Distribution	$3,019,969													
4	General	$499,761													
5	Common	$454,709													
6	TOTAL Utility Plant in Service	$14,155,173	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Reserve for Depreciation														
7	Production	$4,469,343	($6,261)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Transmission	$567,004													
9	Distribution	$1,184,480													
10	General	$179,530													
11	Common	$243,128													
12	TOTAL Reserve for Depreciation	$6,643,485	($6,261)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Net Utility Plant in Service														
13	Production	$3,709,145	$6,261	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Transmission	$1,435,242													
15	Distribution	$1,835,489													
16	General	$320,231													
17	Common	$211,581													
18	Net Utility Plant in Service	$7,511,688	$6,261	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	Utility Plant Held for Future Use	$0													
20	Construction Work in Progress	$570,327	$0	$0	$0	$0	$0	$0	$0	$0	$0	($8)	$0	($225)	$0
21	Less: Accumulated Deferred Income Taxes	$1,668,597	$2,557	($22,627)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	Cash Working Capital	($86,041)													
	Other Rate Base Items:														
23	Materials and Supplies	$116,514	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Fuel Inventory	$74,663	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	Non-Plant Assets & Liabilities	($12,904)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Prepayments	$14,103	$0	($55,349)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
27	Deferred Revenues - Nuc Outage	$0													
28	Nuclear Outage Amortization	$82,801													
29	Customer Advances	($3,301)													
30	Customer Deposits	($2,763)													
31	Sherco 3 Deferral	$10,250													
32	Black Dog Reg Asset Amortization	$2,962													
33	PI EPU Amortization	$55,349													
34	Other Working Capital	$5,202													
35	Total Other Rate Base Items	$342,875	$0	($55,349)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
36	Total Average Rate Base	$6,670,252	$3,705	($32,722)	$0	$0	$0	$0	$0	$0	$0	($8)	$0	($225)	$0

RATE BASE SCHEDULES
RATE BASE ADJUSTMENT SCHEDULES
Xcel Energy Position
2014 Test Year vs 2014 Test Year Hearing Position

($000's)

Line No.	Description	Customer Care Credit	Nuclear Fees	Investor Relations	Hollydale Project	PI EPU/LCM Split	Foundation Cost Correction	Big Stone Brookings Correction	Bargaining Unit Wage Increase	Intangible Theoretical	Xcel NOL Calc	NOL	CWC	Adjusted 2014 Test Year
	Work Paper Reference	24	25	26	38	39	40	41	42	43	44	48	49	
	Electric Plant as Booked													
1	Production	$0	$0	$0	($389)	$0	$0	($2,211)	$0	$0	$0	$0	$0	$8,175,890
2	Transmission													$2,002,245
3	Distribution													$3,019,969
4	General													$499,761
5	Common													$454,709
6	TOTAL Utility Plant in Service	$0	$0	$0	($389)	$0	$0	($2,211)	$0	$0	$0	$0	$0	$14,152,573
	Reserve for Depreciation													
7	Production	$0	$0	$0	($0)	($0)	$0	($24)	$0	$179	$0	$0	$0	$4,463,237
8	Transmission													$567,004
9	Distribution													$1,184,480
10	General													$179,530
11	Common													$243,128
12	TOTAL Reserve for Depreciation	$0	$0	$0	($0)	($0)	$0	($24)	$0	$179	$0	$0	$0	$6,637,378
														$0
	Net Utility Plant in Service													$0
13	Production	$0	$0	$0	($389)	$0	$0	($2,187)	$0	($179)	$0	$0	$0	$3,712,652
14	Transmission													$1,435,242
15	Distribution													$1,835,489
16	General													$320,231
17	Common													$211,581
18	Net Utility Plant in Service	$0	$0	$0	($389)	$0	$0	($2,187)	$0	($179)	$0	$0	$0	$7,515,195
19	Utility Plant Held for Future Use													$0
20	Construction Work in Progress	$0	$0	$0	$0	$0	$0	$2,257	$0	$0	$0	$0	$0	$572,351
21	Less: Accumulated Deferred Income Taxes	$0	$0	$0	$0	($142)	$0	($229)	$0	($73)	($190)	$ (3,402)		$1,644,490
22	Cash Working Capital												$7,878	($78,163)
	Other Rate Base Items:													
23	Materials and Supplies	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$116,514
24	Fuel Inventory	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$74,663
25	Non-Plant Assets & Liabilities	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($12,904)
26	Prepayments	$0	$0	$0	$0	($1,560)	$0	$0	$0	$0	$0	$0	$0	($42,806)
27	Deferred Revenues - Nuc Outage													$0
28	Nuclear Outage Amortization													$82,801
29	Customer Advances													($3,301)
30	Customer Deposits													($2,763)
31	Sherco 3 Deferral													$10,250
32	Black Dog Reg Asset Amortization													$2,962
33	PI EPU Amortization													$55,349
34	Other Working Capital													$5,202
35	Total Other Rate Base Items	$0	$0	$0	$0	($1,560)	$0	$0	$0	$0	$0	$0	$0	$285,966
														$0
36	Total Average Rate Base	$0	$0	$0	($389)	($1,418)	$0	$299	$0	($106)	$190	$3,402	$7,878	$6,650,858

INCOME STATEMENT SCHEDULES
INCOME STATEMENT ADJUSTMENT SCHEDULES
Xcel Energy Position
2014 Test Year vs 2014 Test Year Hearing Position

($000's)

Line No.	Description	Proposed 2014 Test Year	Monti MCC	PI Cancelled Project	PI EPU Debt Return	Cost of Debt	Sales Forecast	Property Taxes	Emissions Chemicals	Surplus Insurance	Qual Pen Measurement Date	FAS 106	Non Qual Pen Measurement Date	FAS 112	Active Health Care	Nuclear Retention Program	Customer Care Credit	Nuclear Fees	Investor Relations	Hollydale Project	PI EPU/LCM Split	Foundation Cost Correction	Big Stone Brookings Correction	Bargaining Unit Wage Increase	Intangible Theoretical	Xcel NOL Calc	Cost of Cap
	Work Paper Reference		2	3	3	12	13	14	15	16	18	19	20	21	22	23	24	25	26	38	39	40	41	42	43	44	47
	Operating Revenues																										
1	Retail	$2,788,744	$0	$0	$0	$0	$15,782	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	Interdepartmental	722	0	0	0	0	(27)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Other Operating	618,556	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	**Total Operating Revenues**	$3,408,022	$0	$0	$0	$0	$15,755	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Expenses																										
	Operating Expenses:																										
5	Fuel & Purchased Energy	$1,086,327	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Power Production	700,453	0	0	0	0	0	0	(2,265)	0	0	0	0	0	0	0	0	(1,000)	0	0	0	0	0	0	0	0	0
7	Transmission	191,916	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Distribution	103,490	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Customer Accounting	48,552	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Customer Service & Information	93,490	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(503)	0	0	0	0	0	0	0	0	0	0
11	Sales, Econ Dvlp & Other	101	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Administrative & General	196,946	0	0	0	0	0	0	0	(1,662)	1,011	(667)	(703)	(421)	(1,057)	(516)	0	0	(78)	0	0	(115)	0	(405)	0	0	0
13	Total Operating Expenses	$2,421,275	$0	$0	$0	$0	$0	$0	($2,265)	($1,662)	$1,011	($667)	($703)	($421)	($1,057)	($516)	($503)	($1,000)	($78)	$0	$0	($115)	$0	($405)	$0	$0	$0
14	Depreciation	$288,489	($12,523)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($57)	$0	($47)	$0	$39	$0	$0
15	Amortization	$33,229	$0	($1,929)	$733	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0	$0	$0	$0
	Taxes:																										
16	Property	$167,546	$0	$0	$0	$0	$0	($9,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2)	$0	$0	$0	$0
17	Deferred Income Tax & ITC	182,784	5,113	1,968	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(1)	(212)	0	(429)	0	(16)	(379)	0
18	Federal & State Income Tax	(76,304)	(35)	(884)	(303)	0	6,518	3,723	937	688	(418)	276	291	174	439	214	208	414	32	4	245	47	463	168	1	150	0
19	Payroll & Other	29,409	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Total Taxes	$303,435	$5,078	$1,084	($303)	$0	$6,518	($5,277)	$937	$688	($418)	$276	$291	$174	$439	$214	$208	$414	$32	$3	$33	$47	$32	$168	($15)	($229)	$0
21	**Total Expenses**	$3,046,428	($7,445)	($845)	$430	$0	$6,518	($5,277)	($1,328)	($975)	$593	($391)	($412)	($247)	($617)	($303)	($295)	($586)	($46)	$3	($24)	($67)	($15)	($237)	$24	($229)	$0
22	Allowance for Funds Used During Construc	$35,027	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($31)	$0	$93	$0	$0	$0	$0
23	**Total Operating Income**	$396,621	$7,445	$845	($430)	$0	$9,237	$5,277	$1,328	$975	($593)	$391	$412	$247	$617	$303	$295	$586	$46	($3)	($7)	$67	$108	$237	($24)	$229	$0
	Calculation of Revenue Requirements																										
24	Rate Base	$6,670,253	$3,705	($32,722)	$0	$0	$0	$0	$0	$0	$0	$0	($8)	$0	($225)	$0	$0	$0	$0	($389)	($1,418)	$0	$299	$0	($106)	$190	$0
25	Required Operating Income	509,607	276	(2,438)	0	(780)	0	0	0	0	0	0	(1)	0	(17)	0	0	0	0	(29)	(106)	0	22	0	(8)	14	(39)
26	Operating Income	396,621	7,445	845	(430)	0	9,237	5,277	1,328	975	(593)	391	412	247	617	303	295	586	46	(3)	(7)	67	108	237	(24)	229	0
27	Income Deficiency	112,986	(7,169)	(3,283)	430	(780)	(9,237)	(5,277)	(1,328)	(975)	593	(391)	(413)	(247)	(634)	(303)	(295)	(586)	(46)	(26)	(99)	(67)	(86)	(237)	16	(215)	(39)
28	Revenue Deficiency	**$192,710**	**($12,227)**	**($5,599)**	**$734**	**($1,330)**	**($15,755)**	**($9,000)**	**($2,265)**	**($1,662)**	**$1,011**	**($667)**	**($704)**	**($421)**	**($1,081)**	**($516)**	**($503)**	**($1,000)**	**($78)**	**($44)**	**($168)**	**($115)**	**($147)**	**($405)**	**$28**	**($367)**	**($66)**
	Rev Def per COSS																										
	Calculation of Income Taxes																										
29	Operating Revenue	$3,408,022	$0	$0	$0	$0	$15,755	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	- Operating Exp	2,421,275	0	0	0	0	0	0	(2,265)	(1,662)	1,011	(667)	(703)	(421)	(1,057)	(516)	(503)	(1,000)	(78)	0	0	(115)	0	(405)	0	0	0
31	- Amortizations	33,229	0	(1,929)	733	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	- Taxes oth than Inc	196,955	0	0	0	0	0	(9,000)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(2)	0	0	0	0
33	Operating Income before Adjs	$756,563	$0	$1,929	($733)	$0	$15,755	$9,000	$2,265	$1,662	($1,011)	$667	$703	$421	$1,057	$516	$503	$1,000	$78	$0	$0	$115	$2	$405	$0	$0	$0
34	Additions to Income	$219,847	$0	($4,813)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($14)	$0	$49	$0	$0	$0	$0
35	Deduct from Income	$1,009,101	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($574)	$0	($1,074)	$0	$0	$638	$0
36	Debt Synchronization	$150,748	$84	($746)	$0	$0	$0	$0	$0	$0	$0	$0	($0)	$0	($5)	$0	$0	$0	$0	($9)	($32)	$0	$7	$0	($2)	$4	$0
37	State Taxable Income	($183,438)	($84)	($2,138)	($733)	$0	$15,755	$9,000	$2,265	$1,662	($1,011)	$667	$703	$421	$1,062	$516	$503	$1,000	$78	$11	$592	$115	$1,118	$405	$2	($642)	$0
38	State Income Tax before Credits	($17,979)	($8)	($210)	($72)	$0	$1,544	$882	$222	$163	($99)	$65	$69	$41	$104	$51	$49	$98	$8	$1	$58	$11	$110	$40	$0	($63)	$0
39	State Tax Credits	$640	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($640)	$0
40	Federal Taxable Income	($164,821)	($76)	($1,928)	($661)	$0	$14,211	$8,118	$2,043	$1,499	($912)	$601	$634	$380	$958	$466	$454	$902	$70	$10	$534	$103	$1,009	$365	$2	($1,219)	$0
41	Fed Income Tax before Credits	($57,687)	($27)	($675)	($231)	$0	$4,974	$2,841	$715	$525	($319)	$210	$222	$133	$335	$163	$159	$316	$25	$3	$187	$36	$353	$128	$1	($427)	$0
42	Federal Tax Credits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
43	Income Tax	($76,304)	($35)	($884)	($303)	$0	$6,518	$3,723	$937	$688	($418)	$276	$291	$174	$439	$214	$208	$414	$32	$4	$245	$47	$463	$168	$1	$150	$0

INCOME STATEMENT SCHEDULES
INCOME STATEMENT ADJUSTMENT SCHEDULES
Xcel Energy Position
2014 Test Year vs 2014 Test Year Hearing Positior

($000's)

Line No.	Description	NOL	CWC	Adjusted Total
	Work Paper Reference	48	49	
	Operating Revenues			
1	Retail	$0	$0	$2,804,526
2	Interdepartmental	0	0	695
3	Other Operating	0	0	618,556
4	**Total Operating Revenues**	$0	$0	$3,423,777
	Expenses			
	Operating Expenses:			
5	Fuel & Purchased Energy	$0	$0	$1,086,327
6	Power Production	0	0	697,188
7	Transmission	0	0	191,916
8	Distribution	0	0	103,490
9	Customer Accounting	0	0	48,552
10	Customer Service & Information	0	0	92,987
11	Sales, Econ Dvlp & Other	0	0	101
12	Administrative & General	0	0	192,334
13	Total Operating Expenses	$0	$0	$2,412,895
14	Depreciation	$0	$0	$275,901
15	Amortization	$0	$0	$32,033
	Taxes:			
16	Property	$0	$0	$158,544
17	Deferred Income Tax & ITC	(6,803)	0	182,025
18	Federal & State Income Tax	7,089	(74)	(55,938)
19	Payroll & Other	0	0	29,409
20	Total Taxes	$286	($74)	$314,039
21	**Total Expenses**	$286	($74)	$3,034,868
22	Allowance for Funds Used During Constr	$0	$0	$35,089
23	**Total Operating Income**	($286)	$74	$423,998
	Calculation of Revenue Requirements			
24	Rate Base	$3,402	$7,878	$6,650,859
25	Required Operating Income	253	587	507,344
26	Operating Income	(286)	74	423,999
27	Income Deficiency	539	513	83,345
28	Revenue Deficiency	**$919**	**$874**	**$142,156**
	Rev Def per COSS			
	Calculation of Income Taxes			
29	Operating Revenue	$0	$0	$3,423,777
30	- Operating Exp	0	0	2,412,895
31	- Amortizations	0	0	32,033
32	- Taxes oth than Inc	0	0	187,953
33	Operating Income before Adjs	$0	$0	$790,897
34	Additions to Income	$0	$0	$215,069
35	Deduct from Income	($18,218)	$0	$989,870
36	Debt Synchronization	$78	$180	$150,306
37	State Taxable Income	$18,141	($180)	($134,209)
38	State Income Tax before Credits	$1,778	($18)	($13,155)
39	State Tax Credits	$640	$0	$640
40	Federal Taxable Income	$17,003	($162)	($120,417)
41	Fed Income Tax before Credits	$5,951	($57)	($42,146)
42	Federal Tax Credits	-	$0	$0
43	Income Tax	$7,089	($74)	($55,938)

RATE BASE SCHEDULES
RATE BASE ADJUSTMENT SCHEDULES
DOC Position
2014 Test Year vs 2014 Test Year Hearing Position
($000's)

Line No.	Description	Proposed 2014 Test Year	2 Monticello EPU In-Service	3 Prairie Island Cancelled EPU	4 Qualified Pension discount rate	5 Qualified Pension 2008 mkt loss	6 FAS 106	7 Total Labor	8 Rate Case and Monti Prudence expenses	11 In-Service Dates for Capital Projects
	Work Paper Reference	(24)								
	Electric Plant as Booked									
1	Production	$8,178,489	($187,281)	$0	$0	$0	$0	$0	$0	($28,989)
2	Transmission	$2,002,245								
3	Distribution	$3,019,969								
4	General	$499,761								
5	Common	$454,709								
6	TOTAL Utility Plant in Service	$14,155,173	($187,281)	$0	$0	$0	$0	$0	$0	($28,989)
	Reserve for Depreciation									
7	Production	$4,469,343	($14,130)	$0	$0	$0	$0	$0	$0	($234)
8	Transmission	$567,004								
9	Distribution	$1,184,480								
10	General	$179,530								
11	Common	$243,128								
12	TOTAL Reserve for Depreciation	$6,643,485	($14,130)	$0	$0	$0	$0	$0	$0	($234)
	Net Utility Plant in Service									
13	Production	$3,709,145	($173,151)	$0	$0	$0	$0	$0	$0	($28,755)
14	Transmission	$1,435,242								
15	Distribution	$1,835,489								
16	General	$320,231								
17	Common	$211,581								
18	Net Utility Plant in Service	$7,511,688	($173,151)	$0	$0	$0	$0	$0	$0	($28,755)
19	Utility Plant Held for Future Use	$0								
20	Construction Work in Progress	$570,327	($34,716)	$0	$0	$0	$0	$0	$0	$15,432
21	Less: Accumulated Deferred Income Taxes	$1,668,597	($43,043)	($22,627)	$0	$0	$0	$0	$0	($2,129)
22	Cash Working Capital	($86,041)								
	Other Rate Base Items:									
23	Materials and Supplies	$116,514	$0	$0	$0	$0	$0	$0	$0	$0
24	Fuel Inventory	$74,663	$0	$0	$0	$0	$0	$0	$0	$0
25	Non-Plant Assets & Liabilities	($12,904)	$0	$0	$0	$0	$0	$0	$0	$0
26	Prepayments	$14,103	$0	$0	$0	$0	$0	$0	$0	$0
27	Deferred Revenues - Nuc Outage	$0								
28	Nuclear Outage Amortization	$82,801								
29	Customer Advances	($3,301)								
30	Customer Deposits	($2,763)								
31	Sherco 3 Deferral	$10,250								
32	Black Dog Reg Asset Amortization	$2,962								
33	PI EPU Amortization	$55,349		($55,349)						
34	Other Working Capital	$5,202								
35	Total Other Rate Base Items	$342,876	$0	($55,349)	$0	$0	$0	$0	$0	$0
36	Total Average Rate Base	$6,670,253	($164,824)	($32,722)	$0	$0	$0	$0	$0	($11,194)

RATE BASE SCHEDULES
RATE BASE ADJUSTMENT SCHEDULES
DOC Position
2014 Test Year vs 2014 Test Year Hearing Position
($000's)

Line No.	Description	13 Sales Forecast	14 Property Taxes	15 Emission Control Chemical Costs	16 Insurance - Surplus dist'ns	18 Qualified Pension meas. date	19 FAS 106 meas. Date	20 Non-Qual Pension Restorat'n Plan	21 FAS 112 meas. Date	22 Active Health Care	23 Nuclear Retention Program
	Work Paper Reference										
	Electric Plant as Booked										
1	Production	$0	$0	$0	$0	$0		$0	$0	$0	$0
2	Transmission										
3	Distribution										
4	General										
5	Common										
6	TOTAL Utility Plant in Service	$0	$0	$0	$0	$0		$0	$0	$0	$0
	Reserve for Depreciation										
7	Production	$0	$0	$0	$0	$0		$0	$0	$0	$0
8	Transmission										
9	Distribution										
10	General										
11	Common										
12	TOTAL Reserve for Depreciation	$0	$0	$0	$0	$0		$0	$0	$0	$0
	Net Utility Plant in Service										
13	Production	$0	$0	$0	$0	$0		$0	$0	$0	$0
14	Transmission										
15	Distribution										
16	General										
17	Common										
18	Net Utility Plant in Service	$0	$0	$0	$0	$0		$0	$0	$0	$0
19	Utility Plant Held for Future Use										
20	Construction Work in Progress	$0	$0	$0	$0	$0		($8)	$0	($225)	$0
21	Less: Accumulated Deferred Income Taxes	$0	$0	$0	$0	$0		$0	$0	$0	$0
22	Cash Working Capital										
	Other Rate Base Items:										
23	Materials and Supplies	$0	$0	$0	$0	$0		$0	$0	$0	$0
24	Fuel Inventory	$0	$0	$0	$0	$0		$0	$0	$0	$0
25	Non-Plant Assets & Liabilities	$0	$0	$0	$0	$0		$0	$0	$0	$0
26	Prepayments	$0	$0	$0	$0	$0		$0	$0	$0	$0
27	Deferred Revenues - Nuc Outage										
28	Nuclear Outage Amortization										
29	Customer Advances										
30	Customer Deposits										
31	Sherco 3 Deferral										
32	Black Dog Reg Asset Amortization										
33	PI EPU Amortization										
34	Other Working Capital										
35	Total Other Rate Base Items	$0	$0	$0	$0	$0		$0	$0	$0	$0
36	Total Average Rate Base	$0	$0	$0	$0	$0		($8)	$0	($225)	$0

RATE BASE SCHEDULES
RATE BASE ADJUSTMENT SCHEDULES
DOC Position
2014 Test Year vs 2014 Test Year Hearing Position
($000's)

Line No.	Description	24 Customer Care O&M Expenses	25 Nuclear Fees	26 Investor Relations Costs	38 Hollydale Project	39 PI EPU/LCM Split	40 Xcel Energy Foundat'n Corr.	41 Big Stone-Brookings Corr.	42 Bargain'g Unit Wage Increase	43 Theo. Reserve Corr.	44 NOL Corr.
	Work Paper Reference										
	Electric Plant as Booked										
1	Production	$0	$0	$0	($389)	($802)	$0	($2,211)	$0	$0	$0
2	Transmission										
3	Distribution										
4	General										
5	Common										
6	TOTAL Utility Plant in Service	$0	$0	$0	($389)	($802)	$0	($2,211)	$0	$0	$0
	Reserve for Depreciation										
7	Production	$0	$0	$0	($0)	($29)	$0	($24)	$0	$179	$0
8	Transmission										
9	Distribution										
10	General										
11	Common										
12	TOTAL Reserve for Depreciation	$0	$0	$0	($0)	($29)	$0	($24)	$0	$179	$0
	Net Utility Plant in Service										
13	Production	$0	$0	$0	($389)	($773)	$0	($2,187)	$0	($179)	$0
14	Transmission										
15	Distribution										
16	General										
17	Common										
18	Net Utility Plant in Service	$0	$0	$0	($389)	($773)	$0	($2,187)	$0	($179)	$0
19	Utility Plant Held for Future Use										
20	Construction Work in Progress	$0	$0	$0	$0	($787)	$0	$2,257	$0	$0	$0
21	Less: Accumulated Deferred Income Taxes	$0	$0	$0	$0	($142)	$0	($229)	$0	($73)	($190)
22	Cash Working Capital										
	Other Rate Base Items:										
23	Materials and Supplies	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Fuel Inventory	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	Non-Plant Assets & Liabilities	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Prepayments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
27	Deferred Revenues - Nuc Outage										
28	Nuclear Outage Amortization										
29	Customer Advances										
30	Customer Deposits										
31	Sherco 3 Deferral										
32	Black Dog Reg Asset Amortization										
33	PI EPU Amortization										
34	Other Working Capital										
35	Total Other Rate Base Items	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
36	Total Average Rate Base	$0	$0	$0	($389)	($1,418)	$0	$299	$0	($106)	$190

RATE BASE SCHEDULES
RATE BASE ADJUSTMENT SCHEDULES
DOC Position
2014 Test Year vs 2014 Test Year Hearing Position
($000's)

Line No.	Description	CIP CCRC (58)	Tax Expense Sync	NOL	CWC	DOC Hearing
	Work Paper Reference					
	Electric Plant as Booked					
1	Production	$0	$0			$7,958,818
2	Transmission					$2,002,245
3	Distribution					$3,019,969
4	General					$499,761
5	Common					$454,709
6	TOTAL Utility Plant in Service	$0	$0			$13,935,501
	Reserve for Depreciation					
7	Production	$0	$0			$4,455,105
8	Transmission					$567,004
9	Distribution					$1,184,480
10	General					$179,530
11	Common					$243,128
12	TOTAL Reserve for Depreciation	$0	$0			$6,629,247
	Net Utility Plant in Service					
13	Production	$0	$0			$3,503,711
14	Transmission					$1,435,242
15	Distribution					$1,835,489
16	General					$320,231
17	Common					$211,581
18	Net Utility Plant in Service	$0	$0			$7,306,254
19	Utility Plant Held for Future Use					$0
20	Construction Work in Progress	$0	$0			$552,280
21	Less: Accumulated Deferred Income Taxes	$0	$0			$1,600,164
22	Cash Working Capital				$12,845	($73,196)
	Other Rate Base Items:					
23	Materials and Supplies	$0	$0			$116,514
24	Fuel Inventory	$0	$0			$74,663
25	Non-Plant Assets & Liabilities	$0	$0			($12,904)
26	Prepayments	$0	$0			$14,103
27	Deferred Revenues - Nuc Outage					$0
28	Nuclear Outage Amortization					$82,801
29	Customer Advances					($3,301)
30	Customer Deposits					($2,763)
31	Sherco 3 Deferral					$10,250
32	Black Dog Reg Asset Amortization					$2,962
33	PI EPU Amortization					($0)
34	Other Working Capital					$5,202
35	Total Other Rate Base Items	$0	$0			$287,527
36	Total Average Rate Base	$0	$0		$12,845	$6,472,701

INCOME STATEMENT SCHEDULES
INCOME STATEMENT ADJUSTMENT SCHEDULES
DOC Position

2014 Test Year vs 2014 Test Year Hearing Position

($000's)

Line No.	Description	Proposed 2014 Test Year	Return on Equity	Monticello EPU In-Service	Prairie Island Cancelled EPU	Qualified Pension discount rate	Qualified Pension 2008 mkt loss	FAS 106	Total Labor	Rate Case and Monti Prudence expenses	In-Service Dates for Capital Projects	Sales Forecast	Property Taxes
	Issue #		1	2	3	4	5	6	7	8	11	13	14
	Operating Revenues												
1	Retail	$2,788,744	$0	$0	$0	$0	$0	$0	$0	$0	$0	$43,259	$0
2	Interdepartmental	722	0	0	0	0	0	0	0	0	0	(31)	0
3	Other Operating	618,556	0	0	0	0	0	0	0	0	0	0	0
4	**Total Operating Revenues**	$3,408,022	$0	$0	$0	$0	$0	$0	$0	$0	$0	$43,228	$0
	Expenses												
	Operating Expenses:												
5	Fuel & Purchased Energy	$1,086,327	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Power Production	700,453	0	0	0	0	0	0	0	0	0	0	0
7	Transmission	191,916	0	0	0	0	0	0	0	0	0	0	0
8	Distribution	103,490	0	0	0	0	0	0	0	0	0	0	0
9	Customer Accounting	48,552	0	0	0	0	0	0	0	0	0	0	0
10	Customer Service & Information	93,490	0	0	0	0	0	0	0	0	0	0	0
11	Sales, Econ Dvlp & Other	101	0	0	0	0	0	0	0	0	0	0	0
12	Administrative & General	196,946	0	0	0	(1,770)	(6,174)	(1,592)	(5,600)	0	0	0	0
13	Total Operating Expenses	$2,421,275	$0	$0	$0	($1,770)	($6,174)	($1,592)	($5,600)	$0	$0	$0	$0
14	Depreciation	$288,489	$0	($12,577)	$0	$0	$0	$0	$0	$0	($1,152)	$0	$0
15	Amortization	$33,229	$0	$0	($1,196)	$0	$0	$0	$0	($418)	$0	$0	$0
	Taxes:												
16	Property	$167,546	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($9,000)
17	Deferred Income Tax & ITC	182,784	0	940	1,968	0	0	0	0	0	(2,654)	0	0
18	Federal & State Income Tax	(76,304)	0	5,386	(1,188)	732	2,554	658	2,317	173	3,239	17,883	3,723
19	Payroll & Other	29,409	0	0	0	0	0	0	0	0	0	0	0
20	Total Taxes	$303,435	$0	$6,326	$780	$732	$2,554	$658	$2,317	$173	$585	$17,883	($5,277)
21	**Total Expenses**	$3,046,428	$0	($6,251)	($416)	($1,038)	($3,620)	($933)	($3,283)	($245)	($567)	$17,883	($5,277)
22	Allowance for Funds Used During Construc	$35,027	$0	($187)	$0	$0	$0	$0	$0	$0	($120)	$0	$0
23	**Total Operating Income**	$396,621	$0	$6,064	$416	$1,038	$3,620	$933	$3,283	$245	$447	$25,345	$5,277
	Calculation of Revenue Requirements												
24	Rate Base	$6,670,253	$0	($164,824)	($32,722)	$0	$0	$0	$0	$0	($11,194)	$0	$0
25	Required Operating Income	509,607	(21,184)	(12,279)	(2,438)	0	0	0	0	0	(834)	0	0
26	Operating Income	396,621	0	6,064	416	1,038	3,620	933	3,283	245	447	25,345	5,277
27	Income Deficiency	112,986	(21,184)	(18,343)	(2,854)	(1,038)	(3,620)	(933)	(3,283)	(245)	(1,281)	(25,345)	(5,277)
28	Revenue Deficiency	**$192,710**	**($36,132)**	**($31,286)**	**($4,867)**	**($1,770)**	**($6,174)**	**($1,592)**	**($5,600)**	**($418)**	**($2,184)**	**($43,228)**	**($9,000)**
	Calculation of Income Taxes												
29	Operating Revenue	$3,408,022	$0	$0	$0	$0	$0	$0	$0	$0	$0	$43,228	$0
30	- Operating Exp	2,421,275	0	0	0	(1,770)	(6,174)	(1,592)	(5,600)	0	0	0	0
31	- Amortizations	33,229	0	0	(1,196)	0	0	0	0	(418)	0	0	0
32	- Taxes oth than Inc	196,955	0	0	0	0	0	0	0	0	0	0	(9,000)
33	Operating Income before Adjs	$756,563	$0	$0	$1,196	$1,770	$6,174	$1,592	$5,600	$418	$0	$43,228	$9,000
34	Additions to Income	$219,847	$0	($21)	($4,813)	$0	$0	$0	$0	$0	($34)	$0	$0

35	Deduct from Income	$1,009,101	$0	($9,282)	$0	$0	$0	$0	$0	$0	($7,609)	$0	$0
36	Debt Synchronization	$150,748	$0	($3,758)	($746)	$0	$0	$0	$0	$0	($255)	$0	$0
37	State Taxable Income	($183,438)	$0	$13,020	($2,871)	$1,770	$6,174	$1,592	$5,600	$418	$7,830	$43,228	$9,000
38	State Income Tax before Credits	($17,979)	$0	$1,276	($281)	$173	$605	$156	$549	$41	$767	$4,236	$882
39	State Tax Credits	$640	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
40	Federal Taxable Income	($164,821)	$0	$11,744	($2,590)	$1,597	$5,569	$1,436	$5,051	$377	$7,063	$38,992	$8,118
41	Fed Income Tax before Credits	($57,687)	$0	$4,110	($906)	$559	$1,949	$502	$1,768	$132	$2,472	$13,647	$2,841
42	Federal Tax Credits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
43	Income Tax	($76,304)	$0	$5,386	($1,188)	$732	$2,554	$658	$2,317	$173	$3,239	$17,883	$3,723

INCOME STATEMENT SCHEDULES
INCOME STATEMENT ADJUSTMENT SCHEDULES
DOC Position

2014 Test Year vs 2014 Test Year Hearing Position

($000's)

Line No.	Description	Emission Control Chemical Costs	Insurance - Surplus dist'ns	Qualified Pension meas. date	FAS 106 meas. Date	Non-Qual Pension Restorat'n Plan	FAS 112 meas. Date	Active Health Care	Nuclear Retention Program	Customer Care O&M Expenses	Nuclear Fees	Investor Relations Costs	Hollydale Project
	Issue #	15	16	18	19	20	21	22	23	24	25	26	38
	Operating Revenues												
1	Retail	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	Interdepartmental	0	0	0	0	0	0	0	0	0	0	0	0
3	Other Operating	0	0	0	0	0	0	0	0	0	0	0	0
4	**Total Operating Revenues**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Expenses												
	Operating Expenses:												
5	Fuel & Purchased Energy	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Power Production	(2,265)	0	0	0	0	0	0	0	0	(1,000)	0	0
7	Transmission	0	0	0	0	0	0	0	0	0	0	0	0
8	Distribution	0	0	0	0	0	0	0	0	0	0	0	0
9	Customer Accounting	0	0	0	0	0	0	0	0	0	0	0	0
10	Customer Service & Information	0	0	0	0	0	0	0	0	(503)	0	0	0
11	Sales, Econ Dvlp & Other	0	0	0	0	0	0	0	0	0	0	0	0
12	Administrative & General	0	(1,662)	1,011	(667)	(703)	(421)	(1,057)	(516)	0	0	(78)	0
13	Total Operating Expenses	($2,265)	($1,662)	$1,011	($667)	($703)	($421)	($1,057)	($516)	($503)	($1,000)	($78)	$0
14	Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)
15	Amortization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Taxes:												
16	Property	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
17	Deferred Income Tax & ITC	0	0	0	0	0	0	0	0	0	0	0	(1)
18	Federal & State Income Tax	937	688	(418)	276	291	174	439	214	208	414	32	4
19	Payroll & Other	0	0	0	0	0	0	0	0	0	0	0	0
20	Total Taxes	$937	$688	($418)	$276	$291	$174	$439	$214	$208	$414	$32	$3
21	**Total Expenses**	($1,328)	($975)	$593	($391)	($412)	($247)	($617)	($303)	($295)	($586)	($46)	$3
22	Allowance for Funds Used During Constru	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	**Total Operating Income**	$1,328	$975	($593)	$391	$412	$247	$617	$303	$295	$586	$46	($3)
	Calculation of Revenue Requirements												
24	Rate Base	$0	$0	$0	$0	($8)	$0	($225)	$0	$0	$0	$0	($389)
25	Required Operating Income	0	0	0	0	(1)	0	(17)	0	0	0	0	(29)
26	Operating Income	1,328	975	(593)	391	412	247	617	303	295	586	46	(3)
27	Income Deficiency	(1,328)	(975)	593	(391)	(413)	(247)	(634)	(303)	(295)	(586)	(46)	(26)
28	Revenue Deficiency	**($2,265)**	**($1,662)**	**$1,011**	**($667)**	**($704)**	**($421)**	**($1,081)**	**($516)**	**($503)**	**($1,000)**	**($78)**	**($44)**
	Calculation of Income Taxes												
29	Operating Revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	- Operating Exp	(2,265)	(1,662)	1,011	(667)	(703)	(421)	(1,057)	(516)	(503)	(1,000)	(78)	0
31	- Amortizations	0	0	0	0	0	0	0	0	0	0	0	0
32	- Taxes oth than Inc	0	0	0	0	0	0	0	0	0	0	0	0
33	Operating Income before Adjs	$2,265	$1,662	($1,011)	$667	$703	$421	$1,057	$516	$503	$1,000	$78	$0
34	Additions to Income	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

35	Deduct from Income	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2)
36	Debt Synchronization	$0	$0	$0	$0	($0)	$0	($5)	$0	$0	$0	$0	($9)
37	State Taxable Income	$2,265	$1,662	($1,011)	$667	$703	$421	$1,062	$516	$503	$1,000	$78	$11
38	State Income Tax before Credits	$222	$163	($99)	$65	$69	$41	$104	$51	$49	$98	$8	$1
39	State Tax Credits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
40	Federal Taxable Income	$2,043	$1,499	($912)	$601	$634	$380	$958	$466	$454	$902	$70	$10
41	Fed Income Tax before Credits	$715	$525	($319)	$210	$222	$133	$335	$163	$159	$316	$25	$3
42	Federal Tax Credits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
43	Income Tax	$937	$688	($418)	$276	$291	$174	$439	$214	$208	$414	$32	$4

INCOME STATEMENT SCHEDULES
INCOME STATEMENT ADJUSTMENT SCHEDULES
DOC Position

2014 Test Year vs 2014 Test Year Hearing Position

($000's)

Line No.	Description	PI EPU/LCM Split	Xcel Energy Foundat'n Corr.	Big Stone-Brookings Corr.	Bargain'g Unit Wage Increase	Theo. Reserve Corr.	NOL Corr.	CIP CCRC	Tax Expense Sync	NOL	CWC	Cost of Cap	DOC Hearing Total
	Issue #	39	40	41	42	43	44	58	47	48	49	47	
	Operating Revenues												
1	Retail	$0	$0	$0	$0	$0	$0	($90,692)	$0	$0	$0	$0	$2,741,311
2	Interdepartmental	0	0	0	0	0	0	(24)	0	0	0	0	667
3	Other Operating	0	0	0	0	0	0	0	0	0	0	0	618,556
4	**Total Operating Revenues**	$0	$0	$0	$0	$0	$0	($90,716)	$0	$0	$0	$0	$3,360,534
	Expenses												
	Operating Expenses:												
5	Fuel & Purchased Energy	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,086,327
6	Power Production	0	0	0	0	0	0	0	0	0	0	0	697,188
7	Transmission	0	0	0	0	0	0	0	0	0	0	0	191,916
8	Distribution	0	0	0	0	0	0	0	0	0	0	0	103,490
9	Customer Accounting	0	0	0	0	0	0	0	0	0	0	0	48,552
10	Customer Service & Information	0	0	0	0	0	0	(90,716)	0	0	0	0	2,271
11	Sales, Econ Dvlp & Other	0	0	0	(405)	0	0	0	0	0	0	0	(304)
12	Administrative & General	0	(115)	0	0	0	0	0	0	0	0	0	177,602
13	Total Operating Expenses	$0	($115)	$0	($405)	$0	$0	($90,716)	$0	$0	$0	$0	$2,307,043
14	Depreciation	($57)	$0	($47)	$0	$39	$0	$0	$0	$0	$0	$0	$274,695
15	Amortization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$31,615
	Taxes:												
16	Property	$0	$0	($2)	$0	$0	$0	$0	$0	$0	$0	$0	$158,544
17	Deferred Income Tax & ITC	(212)	0	(429)	0	(16)	(379)	0	0	0	0	0	182,001
18	Federal & State Income Tax	245	47	463	168	1	150	(0)	2,329	0	(81)	358	(33,885)
19	Payroll & Other	0	0	0	0	0	0	0	0	0	0	0	29,409
20	Total Taxes	$33	$47	$31	$168	($15)	($229)	($0)	$2,329	$0	($81)	$358	$336,068
21	**Total Expenses**	($24)	($67)	($16)	($237)	$24	($229)	($90,716)	$2,329	$0	($81)	$358	$2,949,421
22	Allowance for Funds Used During Constru	($31)	$0	$93	$0	$0	$0	$0	$0	$0	$0	$0	$34,782
23	**Total Operating Income**	($7)	$67	$109	$237	($24)	$229	($0)	($2,329)	($0)	$81	($358)	$445,895
	Calculation of Revenue Requirements												
24	Rate Base	($1,418)	$0	$299	$0	($106)	$190	$0	$0	($0)	$8,544	$0	$6,468,401
25	Required Operating Income	(106)	0	22	0	(8)	14	0	0	(0)	637	(545)	472,840
26	Operating Income	(7)	67	109	237	(24)	229	(0)	(2,329)	0	81	(358)	445,896
27	Income Deficiency	(99)	(67)	(86)	(237)	16	(215)	0	2,329	(0)	556	(187)	26,944
28	Revenue Deficiency	**($168)**	**($115)**	**($147)**	**($405)**	**$28**	**($367)**	**$0**	**$3,973**	**($0)**	**$948**	**($319)**	**$45,955**
	Calculation of Income Taxes												
29	Operating Revenue	$0	$0	$0	$0	$0	$0	($90,716)	$0	$0	$0	$0	$3,360,534
30	- Operating Exp	0	(115)	0	(405)	0	0	(90,716)	0	0	0	0	2,307,043
31	- Amortizations	0	0	0	0	0	0	0	0	0	0	0	31,615
32	- Taxes oth than Inc	0	0	(2)	0	0	0	0	0	0	0	0	187,953
33	Operating Income before Adjs	$0	$115	$2	$405	$0	$0	($0)	$0	$0	$0	$0	$833,924
34	Additions to Income	($14)	$0	$49	$0	$0	$0	$0	$5,630	$0	$0	$0	$220,644

35	Deduct from Income	($574)	$0	($1,074)	$0	$0	$638	$0	$0	-	$0	$0	$991,197
36	Debt Synchronization	($32)	$0	$7	$0	($2)	$4	$0	$0	($0)	$195	($865)	$145,280
37	State Taxable Income	$592	$115	$1,118	$405	$2	($642)	($0)	$5,630	$0	($195)	$865	($81,908)
38	State Income Tax before Credits	$58	$11	$110	$40	$0	($63)	($0)	$552	$0	($19)	$85	($8,029)
39	State Tax Credits	$0	$0	$0	$0	$0	($640)	$0	$0	$0	$0	$0	$0
40	Federal Taxable Income	$534	$103	$1,009	$365	$2	($1,219)	($0)	$5,078	$0	($176)	$781	($73,881)
41	Fed Income Tax before Credits	$187	$36	$353	$128	$1	($427)	($0)	$1,777	$0	($61)	$273	($25,858)
42	Federal Tax Credits	$0	$0	$0	$0	$0	$0	$0	$0	-	$0	$0	$0
43	Income Tax	$245	$47	$463	$168	$1	$150	($0)	$2,329	$0	($81)	$358	($33,886)

EDULES
INCOME STATEMENT ADJUSTMENT SCHEDULES
Xcel Energy Position
2015 Step vs 2015 Step Hearing Position

($000's)

Line No.	Description	2015 Step Increase	Monti EPU	Debt Cost	PTC PV & Border	Property Taxes	Emissions Chemicals	DOE Payments	Cost of Cap	NOL	CWC	Adjusted Total
	Work Paper Reference		2	12	30	32	33	34	47	48	49	
	Operating Revenues											
1	Retail	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	Interdepartmental	0	0	0	0	0	0	0	0	0	0	0
3	Other Operating	37,887	0	0	11,093	0	0	(10,103)	0	0	0	38,877
4	**Total Operating Revenues**	$37,887	$0	$0	$11,093	$0	$0	($10,103)	$0	$0	$0	$38,877
	Expenses											
	Operating Expenses:											
5	Fuel & Purchased Energy	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Power Production	5,959	0	0	0	0	(1,580)	0	0	0	0	4,379
7	Transmission	0	0	0	0	0	0	0	0	0	0	0
8	Distribution	(173)	0	0	0	0	0	0	0	0	0	(173)
9	Customer Accounting	0	0	0	0	0	0	0	0	0	0	0
10	Customer Service & Information	0	0	0	0	0	0	0	0	0	0	0
11	Sales, Econ Dvlp & Other	0	0	0	0	0	0	0	0	0	0	0
12	Administrative & General	0	0	0	0	0	0	0	0	0	0	0
13	Total Operating Expenses	$5,786	$0	$0	$0	$0	($1,580)	$0	$0	$0	$0	$4,206
14	Depreciation	$66,977	$13,725	$0	$0	$0	$0	$0	$0	$0	$0	$80,702
15	Amortization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Taxes:											
16	Property	$7,325	$0	$0	$0	($3,309)	$0	$0	$0	$0	$0	$4,016
17	Deferred Income Tax & ITC	19,614	(6,093)	0	0	0	0	0	0	(5,444)	0	8,076
18	Federal & State Income Tax	(40,768)	685	0	4,589	1,369	654	(4,180)	0	5,405	(24)	(32,270)
19	Payroll & Other	0	0	0	0	0	0	0	0	0	0	0
20	Total Taxes	($13,830)	($5,408)	$0	$4,589	($1,940)	$654	($4,180)	$0	($39)	($24)	($20,178)
21	**Total Expenses**	$58,933	$8,317	$0	$4,589	($1,940)	($926)	($4,180)	$0	($39)	($24)	$64,730
22	Allowance for Funds Used During Construc	($5,284)	($450)	$0	$0	$0	$0	$0	$0	$0	$0	($5,734)
23	**Total Operating Income**	($26,330)	($8,767)	$0	$6,504	$1,940	$926	($5,923)	$0	$39	$24	($31,587)
	Calculation of Revenue Requirements											
24	Rate Base	$411,505	($25,757)	$0	$0	$0	$0	$0	$0	$2,722	$2,579	$391,050
25	Required Operating Income	31,439	(1,919)	1,193	0	0	0	0	(41)	203	192	31,067
26	Operating Income	(26,330)	(8,767)	0	6,504	1,940	926	(5,923)	0	39	24	(31,587)
27	Income Deficiency	57,769	6,848	1,193	(6,504)	(1,940)	(926)	5,923	(41)	164	168	62,654
28	Revenue Deficiency	**$98,533**	**$11,680**	**$2,034**	**($11,093)**	**($3,309)**	**($1,580)**	**$10,103**	**($70)**	**$279**	**$286**	**$106,864**
	Rev Def per COSS											
	Calculation of Income Taxes											
29	Operating Revenue	$37,887	$0	$0	$11,093	$0	$0	($10,103)	$0	$0	$0	$38,877
30	- Operating Exp	5,786	0	0	0	0	(1,580)	0	0	0	0	4,206
31	- Amortizations	0	0	0	0	0	0	0	0	0	0	0
32	- Taxes oth than Inc	7,325	0	0	0	(3,309)	0	0	0	0	0	4,016
33	Operating Income before Adjs	$24,776	$0	$0	$11,093	$3,309	$1,580	($10,103)	$0	$0	$0	$30,655
34	Additions to Income	($3,202)	($49)	$0	$0	$0	$0	$0	$0	$0	$0	($3,251)
35	Deduct from Income	$110,820	($1,118)	$0	$0	$0	$0	$0	$0	$2,593	$0	$112,295
36	Debt Synchronization	$9,300	($587)	$0	$0	$0	$0	$0	$0	$62	$59	$8,834
37	State Taxable Income	($98,546)	$1,656	$0	$11,093	$3,309	$1,580	($10,103)	$0	($2,655)	($59)	($93,725)
38	State Income Tax before Credits	($9,657)	$162	$0	$1,087	$324	$155	($990)	$0	($260)	($6)	($9,185)
39	State Tax Credits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
40	Federal Taxable Income	($88,888)	$1,494	$0	$10,006	$2,984	$1,425	($9,113)	$0	($2,395)	($53)	($84,540)
41	Fed Income Tax before Credits	($31,111)	$523	$0	$3,502	$1,045	$499	($3,189)	$0	($838)	($19)	($29,589)
42	Federal Tax Credits	$0	$0	$0	$0	$0	$0	$0	$0	($6,504)	$0	($6,504)
43	Income Tax	($40,768)	$685	$0	$4,589	$1,369	$654	($4,180)	$0	$5,405	($24)	($32,270)

INCOME STATEMENT SCHEDULES
INCOME STATEMENT ADJUSTMENT SCHEDULES
DOC Position

2015 Step vs 2015 Step Hearing Position
($000's)

Line No.	Description	DOC 2014 Test Year	Xcel Proposed 2015 Step Increase	Starting STEP ROE	STEP Items ROE	Monti EPU Prudency	Monti EPU In-Service	Theoretical Reserve Rate Moderation	Passage of Time	Transmission Retirements	Distribution Retirements	In-Service Dates for Capital Projects
	Issue No.			1	1	2	2	9	10	10	10	11
	Operating Revenues											
1	Retail	$2,741,311	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Interdepartmental	$667	0	0	0	0	0	0	0	0	0	0
4	Other Operating	$618,556	37,887	0	0	0	0	12,633	0	0	0	0
5	**Total Operating Revenues**	$3,360,534	$37,887	$0	$0	$0	$0	$12,633	$0	$0	$0	$0
	Expenses											
	Operating Expenses:											
6	Fuel & Purchased Energy	$1,086,327	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7	Power Production	$697,188	5,959	0	0	0	0	0	0	0	0	0
8	Transmission	$191,916	0	0	0	0	0	0	0	0	0	0
9	Distribution	$103,490	(173)	0	0	0	0	0	0	0	0	0
10	Customer Accounting	$48,552	0	0	0	0	0	0	0	0	0	0
11	Customer Service & Information	$2,271	0	0	0	0	0	0	0	0	0	0
12	Sales, Econ Dvlp & Other	($304)	0	0	0	0	0	0	0	0	0	0
13	Administrative & General	$177,577	0	0	0	0	0	0	0	0	0	0
14	Total Operating Expenses	$2,307,017	$5,786	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Depreciation	$274,690	$66,977	$0	$0	($4,402)	$12,984	$0	$0	($95)	($446)	($1,355)
16	Amortization	$27,944	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Taxes:											
17	Property	$158,546	$7,325	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Deferred Income Tax & ITC	$180,035	19,614	0	0	1,167	(1,596)	0	0	38	179	342
19	Federal & State Income Tax	($30,672)	(40,768)	0	0	1,222	(4,668)	5,226	1,490	(0)	(1)	240
20	Payroll & Other	$29,409	0	0	0	0	0	0	0	0	0	0
21	Total Taxes	$337,318	($13,830)	$0	$0	$2,389	($6,264)	$5,226	$1,490	$38	$178	$582
22	**Total Expenses**	$2,946,969	$58,934	$0	$0	($2,013)	$6,720	$5,226	$1,490	($57)	($268)	($773)
23	Allowance for Funds Used During Con:	$34,782	($5,284)	$0	$0	$0	($264)	$0	$0	$0	$0	$476
24	**Total Operating Income**	$448,347	($26,331)	$0	$0	$2,013	($6,983)	$7,407	($1,490)	$57	$268	$1,249
	Calculation of Revenue Requirements											
25	Rate Base	$6,501,385	$411,505	$0	$0	($53,544)	$135,597	$0	($157,946)	$29	$133	$604
26	Required Operating Income	475,251	31,439	(1,319)	79	(3,989)	10,102	0	(11,767)	2	10	45
27	Operating Income	448,347	(26,330)	0	0	2,013	(6,983)	7,407	(1,490)	57	268	1,249
28	Income Deficiency	26,904	57,770	(1,319)	79	(6,002)	17,085	(7,407)	(10,277)	(55)	(258)	(1,204)
29	Revenue Deficiency	**$45,887**	**$98,533**	**($2,250)**	**$134**	**($10,237)**	**$29,141**	**($12,633)**	**($17,529)**	**($94)**	**($441)**	**($2,054)**
	Calculation of Income Taxes											
30	Operating Revenue	$3,360,534	$37,887	$0	$0	$0	$0	$12,633	$0	$0	$0	$0
31	- Operating Exp	2,307,017	5,786	0	0	0	0	0	0	0	0	0
32	- Amortizations	27,944	0	0	0	0	0	0	0	0	0	0
33	- Taxes oth than Inc	187,955	7,325	0	0	0	0	0	0	0	0	0
34	Operating Income before Adjs	$837,618	$24,776	$0	$0	$0	$0	$12,633	$0	$0	$0	$0
35	Additions to Income	$296	($3,202)	$0	$0	$0	($28)	$0	$0	$0	$0	($22)
36	Deduct from Income	$89,869	$110,820	$0	$0	($1,733)	$8,164	$0	$0	$0	$0	($615)
37	Debt Synchronization	$148,232	9,300	$0	$0	($1,221)	$3,092	$0	($3,601)	$1	$3	$14
38	State Taxable Income	$599,814	($98,546)	$0	$0	$2,954	($11,284)	$12,633	$3,601	($1)	($3)	$579
39	State Income Tax before Credits	$58,782	($9,657)	$0	$0	$289	($1,106)	$1,238	$353	($0)	($0)	$57
40	State Tax Credits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
41	Federal Taxable Income	$541,032	($88,888)	$0	$0	$2,664	($10,178)	$11,395	$3,248	($1)	($3)	$523
42	Fed Income Tax before Credits	$189,361	($31,111)	$0	$0	$933	($3,562)	$3,988	$1,137	($0)	($1)	$183
43	Federal Tax Credits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
44	Income Tax	$248,143	($40,768)	$0	$0	$1,222	($4,668)	$5,226	$1,490	($0)	($1)	$240

PTCs for Pleasant Valley and Border Winds	Property Taxes	Emissions Control Chemical Costs	Income Statement CWC	Int Sync	2014 Base Debt Rate	Starting STEP Cap Structure	STEP Items Cap Structure	Adjustments	Total Adjusted
30	32	33	49	47					
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
0	0	0	0	0	0	0	0	0	0
11,093	0	0	0	0	0	0	0	23,726	61,613
$11,093	$0	$0	$0	$0	$0	$0	$0	$23,726	$61,613
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
0	0	(1,580)	0	0	0	0	0	(1,580)	4,379
0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	(173)
0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0
$0	$0	($1,580)	$0	$0	$0	$0	$0	($1,580)	$4,206
$0	$0	$0	$0	$0	$0	$0	$0	$6,686	$73,663
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	($3,309)	$0	$0	$0	$0	$0	$0	($3,309)	$4,016
0	0	0	0	0	0	0	0	130	19,744
4,589	1,369	654	36	(1,813)	0	8	0	8,351	(32,418)
0	0	0	0	0	0	0	0	0	0
$4,589	($1,940)	$654	$36	($1,813)	$0	$8	$0	$5,172	($8,658)
									0
$4,589	($1,940)	($926)	$36	($1,813)	$0	$8	$0	$10,278	$69,212
									0
$0	$0	$0	$0	$0	$0	$0	$0	$212	($5,072)
									0
$6,504	$1,940	$926	($36)	$1,813	$0	($8)	$0	$13,661	($12,670)
		1748							
$0	$0	$0	($3,798)	$0	$0	$0	$0	($78,925)	$332,579
0	0	0	(283)	0	1,950	85	8	(5,077)	26,362
6,504	1,940	926	0	1,813	0	0	0	13,705	(12,625)
(6,504)	(1,940)	(926)	(283)	(1,813)	1,950	85	8	(18,782)	38,988
($11,093)	**($3,309)**	**($1,580)**	**($483)**	**($3,093)**	**$3,327**	**$145**	**$14**	**($32,035)**	**$66,498**
$11,093	$0	$0	$0	$0	$0	$0	$0	$23,726	$61,613
0	0	(1,580)	0	0	0	0	0	(1,580)	4,206
0	0	0	0	0	0	0	0	0	0
0	(3,309)	0	0	0	0	0	0	(3,309)	4,016
$11,093	$3,309	$1,580	$0	$0	$0	$0	$0	$28,615	$53,391
$0	$0	$0	$0	$0	$0	$0	$0	($50)	($3,252)
$0	$0	$0	$0	$0	$0	$0	$0	$5,816	$116,636
$0	$0	$0	($87)	$4,383	0	(20)	0	$2,564	$11,864
$11,093	$3,309	$1,580	$87	($4,383)	$0	$20	$0	$20,185	($78,361)
$1,087	$324	$155	$8	($430)	$0	$2	$0	$1,978	($7,679)
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$10,006	$2,985	$1,425	$78	($3,953)	$0	$18	$0	$18,207	($70,681)
$3,502	$1,045	$499	$27	($1,384)	$0	$6	$0	$6,372	($24,738)
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$4,589	$1,369	$654	$36	($1,813)	$0	$8	$0	$8,351	($32,418)

Table of Contents

Table of Contents

Table of Contents

Table of Contents

PART 1 – DEPARTMENT REVENUE REQUIREMENTS ISSUES

A. Disputed Department Issues – Revenue Requirements

1. Return on Equity (ROE)

Disputed among NSP, the Department, CEI, ICI Group, Commercial Group, and AARP. No other party provided testimony on this issue.

NSP position: the Company recommended an ROE of 10.25 percent, based on an analysis which supports a range of 10.00 percent to 10.70 percent, with a 80 percent/20 percent weighting of electric and combination company comparable groups. In Rebuttal Testimony, the Company continued to support its recommendation based on an updated analysis through May 30, 2014. The Company also explained its position that it would be inappropriate to reduce the authorized ROE below the 9.80 percent proposed by the Department in Direct Testimony, citing the following factors: current financial market volatility and changing conditions; the two-year period during which the ROE will be in effect; the Company's ongoing need to fund substantial capital expenditures; and the likely negative effect on investors of a second successive decrease in the ROE, which would move the Company's ROE toward the bottom of ROE awards since August 2013. The Company also explained that the ICI Group's methodology and analysis are inconsistent with available data, based on an inappropriate comparable group and unsound applications, and not representative of NSPM's market-based cost of equity. The Commercial Group did not perform an independent analysis of the Company's cost of equity. The Company believed it is common to include Construction Work in Progress (CWIP) in rate base and CWIP does not warrant an adjustment to the ROE. It would also be inappropriate to reduce the Company's ROE in connection with its proposed decoupling mechanism, as proposed by AARP.

Department position: the Company did not show its proposed ROE to be reasonable. The Department originally recommended an ROE of 9.80 percent, the midpoint of a range of 8.97 percent to 10.62 percent, based on a 60 percent/40 percent weighting of the Final Electric Comparison Group (FEGC) and Final Combination Comparison Group (FCCG). In Surrebuttal, the Department recommended a 9.64 percent ROE, the midpoint of the updated range of 8.90 percent to 10.39 percent, based on an updated Discount Cash Flow (DCF) analysis for June 7, 2014 to July 7, 2014 and adjustments to the FECG and FCCG. The Department disagreed with the basis and positions of the ICI Group, because its comparison group was inaccurate and DCF analyses were flawed for several reasons. The Department also disagreed with the Commercial Group's recommendations because the information it used was outdated and CWIP does not justify an adjustment to the ROE. The Department also stated that the AARP proposal should be rejected, because the Company's comparison groups capture any decoupling impact on risk and therefore, no additional adjustment to the ROE is needed.

CEI position: CEI stated that if the Commission approves a decoupling mechanism in this case, it should not change the Company's ROE for any reasons that are associated with the adoption of decoupling.

ICI Group position: the ICI Group recommended an ROE of 9.0 percent, based on its DCF analyses of comparable retail electric utility companies. The ICI Group stated that the 9.0 percent rate falls within the range of the decisions rendered and settlements approved by state regulators for comparable electric utilities in recent months.

Commercial Group position: the Commercial Group stated that the Company's requested ROE is higher than ROEs authorized by other jurisdictions (the average for vertically integrated utilities from 2012-2014 being 10.03 percent according to SNL Financial). The Commercial Group suggested that if CWIP is included in rate base, the ROE should be reduced because CWIP shifts risk from the Company to the ratepayers.

AARP position: AARP pointed out that decoupling shifts risks from shareholders to ratepayers, and the ROE in this case should be adjusted downward to reflect this shift. If decoupling is approved by the Commission, AARP recommended a 10-basis point reduction in ROE or setting ROE at the low end of the range of reasonable returns.

Record Citations:
Sparby Opening Statement, Exh. 113 at 3
Evidentiary Hearing Transcript, Vol. 1 at 30, 42-43, 48-49 (Sparby)
Hevert Direct, Exh. 27 at 2, 28-45, 54-56
Hevert Rebuttal, Exh. 28 at 2-58
Hevert Surrebuttal, Exh. 29 at 1-13
Hevert Opening Statement, Exh. 115 at 1-5
Evidentiary Hearing Transcript, Vol. 1 at 54-101 (Hevert)
Tyson Direct, Exh. 30 at 26
Amit Direct, Exh. 400 at 2-68
Amit Rebuttal, Exh. 402 at 1-16
Amit Surrebuttal, Exh. 403 at 1-30
Amit Opening Statement, Exh. 443 at 1-4
Evidentiary Hearing Transcript, Vol. 4 at 31-49 (Amit)
Evidentiary Hearing Transcript, Vol. 5 at 74 (Lusti)
Cavanagh Direct, Exh. 290 at 5-6
Cavanagh Rebuttal, Exh. 294 at 6
Cavanagh Opening Statement, Exh. 300 at 1
Evidentiary Hearing Transcript, Vol. 3 61-62, 68-71, 87-89 (Cavanagh)
Glahn Direct, Exh. 250 at 15-25
Glahn Surrebuttal, Exh. 251 at 4-5
Glahn Opening Statement, Exh. 254 at 1
Evidentiary Hearing Transcript, Vol. 3 at 111-135 (Glahn)
Chriss Direct, Exh. 225 at 8-9, 11
Brockway Direct, Exh. 310 at 18, 21-22
Brockway Rebuttal, Exh. 311 at 14-21
Brockway Surrebuttal, Exh. 312 at 6-8

2. Monticello LCM/EPU Project – Used and Useful (In-Service Date) (2014 and/or 2015 Step)

Partially resolved between NSP and MCC, disputed by the Department and XLI. No other party provided testimony on this issue.

NSP position: as part of its initial filing, the Company proposed to place the Monticello LCM/EPU Project into service as of January 2014 for regulatory accounting purposes. The Company believed its proposal is appropriate because the LCM/EPU Project is used and useful. The Company received the two required license amendments (EPU and MELLLA+) in December 2013 and March 2014, which means that the Company is currently operating under an amended license that allows operations at the increased 671 MWe level. The LCM/EPU Project equipment is currently in place, and used in current plant operations and power ascension to the increased level. Also, during the test year, the Company reached the first required data collection point and operated the plant at an uprated level of 640 MWe for approximately 20 days. The Company acknowledged there was a delay in the power ascension process, but confirmed its expectation that the plant will reach the full 671 MWe before the end of 2014. During the Evidentiary Hearing, the Company accepted the MCC proposal to defer the 2014 Monticello EPU depreciation expense and amortize the expense over the life of the facility (resulting in a $12.227 million decrease in the 2014 test year revenue requirements and $11.680 million increase in the 2015 Step revenue requirements). The Company requested to add $11.680 million in Monticello EPU costs to the 2015 Step. The Company recommended that the MCC proposal regarding purchased power costs be addressed in the annual automatic adjustment (AAA) Docket.

Department position: the Company did not show the reasonableness of its position. The Department stated that there are several uncertainties regarding the Monticello EPU in-service date, and facts do not support placing the EPU project into service during the test year since the plant is not yet used and useful. Specifically, the Department noted that the plant has operated at the reduced 600 MWe level since March 11, 2014, and is not operating at the higher 640MWe level, nor the full 671 MWe level. The EPU cannot be considered used and useful until the NRC allows the Company to resume power ascension testing and to operate the plant at the full 671 MWe. There are uncertainties regarding the NRC data review and the Department believed it was unlikely that the plant could resume power ascension testing in August 2014. Based on the facts in the case, the Department believed that Monticello EPU (71 MW) will not be available for most if not all of the 2014 test year. Also, human performance errors appear to have contributed to the power ascension testing issues and delays. The Department recommended disallowing the Monticello EPU depreciation expense and removing Monticello EPU from the rate base for the 2014 test year. If the Monticello EPU does not operate successfully at the full 671 MWe level by January 2015, the Department recommends that the EPU project be subject to the refund mechanism for the Multi-Year Rate Plan (MYRP). The Department disagreed with the MCC and Company proposal to remove and amortize depreciation and direct expenses over the life of the facility, because this approach would only shift costs onto ratepayers and increase future rates. The Department suggested that the issue of purchase power costs be addressed in the AAA Docket.

MCC position: MCC recommended: 1) treating the delay in operating the plant at the 671 MWe level as a mechanical failure consistent with the decision in the last rate case regarding Sherco Unit 3 outage, 2) removing the depreciation and direct expenses related to the Monticello EPU from the 2014 test year and amortizing them over the life of the facility, 3) removing and amortizing replacement fuel and power costs ($11,103,828), which could be tracked and refunded to rate payers through the Fuel Clause Adjustment (FCA) Rider, and 4) requiring the Company to provide status updates of the ascension to the 671 MWe uprate level. MCC believed that current ratepayers should pay either for the plant put in rate base or for the replacement power costs, but not both. MCC also stated that if its recommendation is not accepted, then the entire EPU portion should be removed from the rate base until 2015 or later.

XLI position: XLI stated that the Monticello EPU will not be used and useful until the complete uprate of 71 MWe is in service and the plant can operate at that capacity on a sustainable basis. XLI recommended that the Commission make a proportional adjustment based on the date when the full 71 MWe is in service, for example, if the current credible estimate is December 2014, then revenue requirements associated with at least 11/12ths of the EPU costs should be removed from the 2014 test year.

Disputed amount: various. The Department: $31.284 million reduction in revenue requirements in 2014 and $18.901 million increase in revenue requirements in 2015 Step. MCC and the Company: $12.227 million reduction in revenue requirements in 2014 and $11.680 million increase in revenue requirements in 2015 Step (removing and amortizing the depreciation expense only). XLI: $28.551 million reduction in revenue requirements in 2014 and $26.406 million increase in revenue requirements in 2015 Step.

Record Citations:
Heuer Direct, Exh. 88 at 12
Heuer Rebuttal, Exh. 90 at 25-27, 31-32
Heuer Opening Statement, Exh. 140 at 3, 8
Evidentiary Hearing Transcript, Vol. 3 at 141, 147, 155-160 (Heuer)
Sparby Rebuttal, Exh. 26 at 17-18
Clark Rebuttal, Exh. 100 at 21-25
Clark Surrebuttal, Exh. 101 at 6-8
Clark Opening Statement, Exh. 134 at 1
Evidentiary Hearing Transcript, Vol. 2 at 112, 121-123 (Clark)
O'Connor Direct, Exh. 51 at 15-32
O'Connor Rebuttal, Exh. 53 at 2-19
O'Connor Surrebuttal, Exh. 55 at 1-5
O'Connor Opening Statement, Exh. 123 at 1-2
Evidentiary Hearing Transcript, Vol. 1 at 218-220, 227-235, 238-245 (O'Connor)
Perkett Direct, Exh. 92 at 13, 21-22
Perkett Rebuttal, Exh. 94 at 43-47, 54
Perkett Opening Statement, Exh. 130 at 2
Evidentiary Hearing Transcript, Vol. 2 at 56-57, 75-78, 82-86, 88-92 (Perkett)
Robinson Rebuttal, Exh. 97 at 19-21
Campbell Direct, Exh. 429 at 42-58
Campbell Surrebuttal, Exh. 435 at 32-59
Campbell Opening Statement, Exh. 450 at 3
Evidentiary Hearing Transcript, Vol. 5 at 17-18, 30-32, 57-58 (Campbell)
Lusti Direct, Exh. 437 at 22, 39
Lusti Surrebuttal, Exh. 442 at 10, 41-42
Lindell Direct, Exh. 370 at 32-34
Schedin Direct, Exh. 340 at 3-9
Schedin Surrebuttal, Exh. 342 at 1-6
Evidentiary Hearing Transcript, Vol. 3 at 177-187 (Schedin)

Pollock Direct, Exh. 260 at 20-23
Pollock Surrebuttal, Exh. 263 at 20-23
Pollock Opening Statement, Exh. 264
Evidentiary Hearing Transcript, Vol. 3 at 29-30, 39-40 (Pollock)

3. Prairie Island Cancelled EPU Project (2014)

Resolved between NSP and the Department, disputed by OAG, MCC, and ICI Group. No other party provided testimony on this issue.

NSP position: the Company requested recovery of $66.1 million in expenses for the cancelled Prairie Island EPU project plus accrued AFUDC of $12.8 million (Total Company). The Company believed that the appropriate standard of review that should be applied to the Prairie Island cancelled EPU project is the prudence standard, which requires the Commission to determine whether the Company actions fell within a range of reasonableness based on the known circumstances at the time the actions were taken. The Company believed that the initiation, management, suspension, and cancellation of the Prairie Island EPU project were carried out in a prudent manner and resulted in reasonable costs for a project of this size, complexity, and regulatory requirements. The Company disagreed with the OAG's recommendation to disallow the $10.1 million pretax charge. The pretax charge is a financial reporting convention to recognize the uncertainty of full recovery of the EPU costs, required by Generally Accepted Accounting Principles (GAAP). During the Evidentiary Hearing, the Company and Department agreed to the Department's alternative proposal to amortize the Prairie Island EPU project costs over the remaining life of the facility with a debt-only return of 2.24 percent ($4.867 million reduction in revenue requirements).

Department position: the Department agreed that the Commission has allowed recovery of cancelled project costs in other rate cases as long as they were prudently incurred. All the costs requested by the Company should be recoverable because the requested amount is far less than the project costs proposed in the Certificate of Need Docket and the Company filed a timely Notice of Changed Circumstances with the Commission. The Department agreed that the EPU costs totaling $66.1 million and AFUDC costs totaling $12.8 million are eligible for recovery. However, the Department recommended that the $78.9 million to be recovered over the remaining life of the facility (20.3 years), without a return on the asset, because this adjustment provides a reasonable sharing of the costs between shareholders and ratepayers. If the Commission will allow a debt-only return on the asset, it should be 2.24 percent, reflecting the capitalization ratio for debt, and be fixed at this amount. During the Evidentiary Hearing, the Company and Department agreed to the Department's alternative proposal to amortize the Prairie Island EPU projects costs over the remaining life of the facility with a debt-only return of 2.24 percent.

OAG position: the OAG noted that the Company did not timely inform the Commission and Parties about the increasing risks and reduced benefits that it had identified internally and it took until October 2012 for the Company to revise its position and file for the cancellation of the Certificate of Need. The OAG believed that because the Company failed to timely cancel the EPU project, some of the project costs were excessive and imprudent. The Company also wrote off $10.1 million of EPU project costs in 2012, and this amount should not be eligible for recovery in this rate case. The OAG recommended that the Company should be denied recovery of $10.1 million equal to the amount of the write-off plus $12.8 million (Total Company) of AFUDC accrued in 2011-2012 when the EPU project was no longer viable and ongoing. In addition, the OAG recommended that any allowed costs be recovered over a 10-year period without a return on the asset.

MCC position: MCC recommended that the Company be allowed to recover the requested project costs and AFUDC over the remaining life of the facility (20.3 years) without earning an equity return on the asset, and with only half year recovery of the amortization expense in 2014. Under the circumstances of the project, ratepayers should not be required to pay an equity return on the asset. MCC did not oppose the Department's recommendation.

ICI Group position: ICI Group recommended that the Commission should deny recovery of all costs associated with the cancelled EPU project, because the EPU project was never a used and useful asset to ratepayers. If the Commission allows recovery of any project costs, these should be amortized over the remaining life of the facility without a return. If the Commission allows any return on the asset, it should be closer to a U.S. Treasury bill or bond interest rate than the Company's usual rate of return.

Disputed amount: various; $4.867 million reduction in revenue requirements (Company and Department), $4.398 million reduction in revenue requirements (OAG), $5.475 million reduction in revenue requirements (MCC), $8.595 million reduction in revenue requirements (ICI Group).

Record Citations:
Sparby Rebuttal, Exh. 26 at 20
Clark Direct, Exh. 99 at 30-41
Clark Rebuttal, Exh. 100 at 48-59
Clark Opening Statement, Exh. 134 at 1
Evidentiary Hearing Transcript, Vol. 2 at 112 (Clark)
Heuer Direct, Exh. 88 at 90-91
Heuer Rebuttal, Exh. 90 at 14-17, 33-34
Heuer Opening Statement, Exh. 140 at 1
Evidentiary Hearing Transcript, Vol. 3 at 139-140 (Heuer)
O'Connor Direct, Exh. 52 at 127-130
Evidentiary Hearing Transcript, Vol. 1 at 223-224 (O'Connor)
Alders Direct, Exh. 48 at 8-22
Alders Opening Statement, Exh. 121 at 1-2
Evidentiary Hearing Transcript, Vol. 1 at 187-193 (Alders)
McCall Direct, Exh. 49 at 12-39
McCall Opening Statement, Exh. 122 at 1-2
Evidentiary Hearing Transcript, Vol. 1 at 199-213 (McCall)
Weatherby Direct, Exh. 45 at 5-28
Weatherby Rebuttal, Exh. 47 at 1-9
Weatherby Opening Statement, Exh. 120 at 1-2
Evidentiary Hearing Transcript, Vol. 1 at 180-185, 193-198 (Weatherby)
Perkett Rebuttal, Exh. 94 at 31-36
Perkett Opening Statement, Exh. 130 at 2-3
Lusti Direct, Exh. 437 at 12-18
Lusti Surrebuttal, Exh. 442 at 3-7
Evidentiary Hearing Transcript, Vol. 5 at 83-84 (Lusti)

Lindell Direct, Exh. 370 at 35-44
Lindell Surrebuttal, Exh. 373 at 17-24
Lindell Opening Statement, Exh. 141 at 2
Evidentiary Hearing Transcript, Vol. 3 at 192-194, 216-217 (Lindell)
Schedin Direct, Exh. 340 at 10-11
Schedin Surrebuttal, Exh. 342 at 6-7
Glahn Direct, Exh. 250 at 10-12
Glahn Surrebuttal, Exh. 251 at 2-3

4. Qualified Pension – Discount Rate (2014)
5. Qualified Pension – 2008 Market Loss (2014)

Disputed between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company stated its selection of pension plan assumptions is subject to significant oversight by outside entities, their guidelines, and its own auditor. During the Evidentiary Hearing, the Company accepted the Department's recommendation that the Company should address in its initial filing of the next rate case why the Company's target asset allocations for its pension fund are reasonable, including ages of retirees and employees, and to address investment strategies and target asset allocations since 2007.

- XES Plan Discount Rate: the Company proposed a discount rate of 4.74 percent to determine the XES Plan pension expense. The calculation of the discount rate under FAS 87 for the XES Plan closely reflects market interest rates and a blended cost of a portfolio of high quality corporate bonds that match the timing of the Company's pension obligations. The proposed discount rate is representative of actual interest rates and is comparable to the average discount rates recently used by other utilities and large companies. Additionally, there has now been a long period of sustained low interest rates, and the primary reason to change the discount rate in the last rate case is no longer valid (i.e., abnormally low interest rates). Lastly, separating the discount rate calculation for financial accounting purposes and for ratemaking purposes is an artificial division between the Company's actual costs and allowed rate recovery. The economic conditions that lead to a lower discount rate for the XES Plan also support the low cost of long-term debt, and both should be reflected consistently.

- 2008 Market Loss: the Company has met its burden of proof and demonstrated that it would be appropriate to recover the 2008 Market Loss. The Company's qualified pension plans have been consistent in reflecting the prior years' pension gain or loss in the current year pension expense. Although NSPM Plan (using ACM) and XES Plan (using FAS 87) methods differ, basically all prior-period gains and losses are netted, and then the net amount either increases or decreases the asset value, which then is compared to future liabilities to determine the amount of unfunded liabilities. Treatment of the 2008 market and liability losses were no exception and followed these practices. The Company has calculated its qualified pension expense consistently, in accordance with Financial Accounting Standards Board and Commission standards, and has not included a separate adjustment for the 2008 Market Loss. The Company believed it would be inequitable to exclude part of the 2008 Market Loss from the qualified pension expense calculation, because the Company's customers have benefitted from large market gains in prior years, and did not pay any pension expense at all during several years before 2008. The Company has prudently managed its Pension trust investments, which must be diversified into different asset classes for the benefit of all pension plan participants, and these asset classes performed well in relation to their benchmarks.

- The Company proposed to continue to limit the XES Plan expense to the 2011 level cap of $6.1 million and defer the difference as well as extend the amortization period for prior-period gains and losses from 10 years to 20 years for the ACM portion (NSPM Plan) of pension. To the extent the Commission prefers a mechanism to further moderate the rate offset of the 2008 Market Loss, the Company also offered two slightly different proposals that would compare a five-year average, normalized qualified pension expense to the actual qualified pension expense each year, and use deferral for the difference for the period from January 1, 2014 to December 31, 2018. The Company believed that if the Commission is inclined to adopt some mechanism to moderate the qualified pension expense, it should adopt one of these alternative proposals instead of changing the discount rate for the XES Plan, which would create an artificial liability gain and depart from GAAP accounting.

Department position: the Company did not show the reasonableness of its position. The Department noted that the assumptions used to estimate pension costs should be reasonable and independently verifiable to ensure that the amount the ratepayers pay now for future employee benefits is reasonable. The Department attached the Towers Watson actuarial certificate which stated Xcel Energy (and not Towers Watson) selected the pension assumptions. The Department also recommended that the Commission require the Company to address in its initial filing of the next rate case why the Company's target asset allocations for its pension fund are reasonable, including ages of retirees and employees, and to address investment strategies and target asset allocations since 2007.

- XES Plan Discount Rate: the Department recommended setting the XES Plan discount rate at 7.25 percent for several reasons. The Department did not agree that the XES Plan discount rate used by the Company is independently established. Furthermore, the Company's discount rate of 4.74 percent is artificially low compared to the EROA of 7.25 percent because it relies on a point-in-time measurement, and because it is calculated based on an accounting method that is used for financial statement reporting purposes. The Department noted that the Aggregated Cost Method (ACM) for the NSPM plan relies on a longer-term prospective and already uses the same discount rate and EROA, consistent with pension funding methodology. The Department also believed that using a discount rate that is lower than the EROA artificially overstates pension expense for ratemaking purposes and is therefore unreasonable. There is no reason to use different discount rates and EROA rates, because the time period for discounting the pension liability to today's dollars and the EROA for determining future value of pension assets is the same time period, it is not reasonable for ratemaking to use different rates. The Department did not agree that raising the Company's expected discount rate in a rate case so that it equals the EROA would have a negative impact on the Company's funding as required by Employee Retirement Income Security Act (ERISA). Rather, ERISA's use of the same discount rate and EROA for funding purposes reaffirms the Department's recommendation regarding the appropriate discount rate to be used for test-year pension expense for determining rates to be charged to ratepayers in this rate case. Additionally, in the Company's last rate case, the Administrative Law Judge (ALJ) and Commission approved the method of using the same discount rate and EROA for the XES Plan. The Department opposed using an average of discount rates to determine the discount rate because the Company in the last rate case attempted to arbitrarily change its assumptions, which resulted in a very small adjustment when averaging. The Department's recommendation reduces the revenue requirements by 1.77 million (both O&M and capital).

- 2008 Market Loss: the Company did not show the reasonableness of its position. The Department recommended that the Company be allowed to recover only 50 percent of the 2008 market loss ($6.17 million reduction in O&M and capital expense). The Department stated that it would be unreasonable to require ratepayers to cover all of this extreme amount of $12.1 million for the 2008 market loss of $19.9 million pension expense in 2014. The Department was also concerned that despite the financial market returning to levels above pre-2008 market loss levels, the Company included over 60 percent of the 2008 market loss in the 2014 pension expense and attempted to get recovery of all of the 2008 market loss in the short term. The Department disagreed with the Company's claim of symmetry for pension, because when pension expense is negative in a rate case, the Company does not refund negative pension expense to ratepayers. Further, the Department stated that it is troubling that the ratepayers pay all the Company's generous pension plan expenses, because no contribution by employees result in the Company including 100 percent of pension expense in rates, including the four percent match of the 401K plan, plus all other benefits as provided on pages 104-107 of Campbell Direct. In addition, the Department disagreed that the Company showed it prudently managed pension assets and, in fact, raised concerns about the Company's management of its pension assets.

- If the Commission does not agree with the Department's recommendations, then the Department will support the Company's second alternative normalization proposal, with additional modification recommendations.

Disputed amount: $7.94 million adjustment and reduction in revenue requirements (both O&M and capital).

Record Citations:
Qualified Pension in General
Heuer Rebuttal, Exh. 90 at 17-20
Tyson Opening Statement, Exh. 116 at 2-3
Evidentiary Hearing Transcript, Vol. 1 at 105-107, 125-132 (Tyson)
Moeller Direct, Exh. 81 at 12-44
Schrubbe Rebuttal, Exh. 83 at 1-8
Evidentiary Hearing Transcript, Vol. 2 at 20 (Schrubbe)
Figoli Direct, Exh. 78 at 66-73
Wickes Rebuttal, Exh. 85 at 1-9
Campbell Direct, Exh. 429 at 99-119, 134-136, 171-173
Campbell Surrebuttal, Exh. 435 at 74-79, 88
Campbell Opening Statement, Exh. 450 at 4
Evidentiary Hearing Transcript, Vol. 5 at 21-22 (Campbell)

Discount Rate Assumption
Moeller Direct, Exh. 81 at 80-92

Schrubbe Rebuttal, Exh. 83 at 39-47
Schrubbe Opening Statement, Exh. 126 at 2-3
Evidentiary Hearing Transcript, Vol. 2 at 21-22, 26-30 (Schrubbe)
Tyson Rebuttal, Exh. 31 at 21-23
Campbell Direct, Exh. 429 at 114-119, 171-172
Campbell Surrebuttal, Exh. 435 at 79-87
Campbell Opening Statement, Exh. 450 at 5-6
Evidentiary Hearing Transcript, Vol. 5 at 39-44, 56-57, 66-68, 69-71 (Campbell)
Lusti Surrebuttal, Exh. 442 at 11

<u>2008 Market Loss</u>
Moeller Direct, Exh. 81 at 18-64
Schrubbe Rebuttal, Exh. 83 at 15-29
Schrubbe Opening Statement, Exh. 126 at 1-2
Evidentiary Hearing Transcript, Vol. 2 at 18-20, 31-34 (Schrubbe)
Wickes Rebuttal, Exh. 85 at 9-11
Tyson Rebuttal, Exh. 31 at 17-20 and Schedule 1
Tyson Opening Statement, Exh. 116 at 2-3
Evidentiary Hearing Transcript, Vol. 1 at 105-107, 125-132 (Tyson)
Campbell Direct, Exh. 429 at 124-134, 172-173
Campbell Surrebuttal, Exh. 435 at 89-95
Campbell Opening Statement, Exh. 450 at 6-7
Evidentiary Hearing Transcript, Vol. 5 at 33-39, 64-65, 68 (Campbell)
Lusti Surrebuttal, Exh. 442 at 11

<u>Alternative Proposals</u>
Schrubbe Rebuttal, Exh. 83 at 30-39
Evidentiary Hearing Transcript, Vol. 2 at 29-30 (Schrubbe)
Campbell Surrebuttal, Exh. 435 at 95-102
Campbell Opening Statement, Exh. 450 at 7-8

6. Retiree Medical Expenses (FAS 106) – Discount Rate and 2008 Market Loss (2014)

Disputed between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company requested recovery of $4.10 million in O&M expenses and $1.16 million in capital costs related to post-retirement medical expenses for certain employees who retired prior to 2000. The Company did not agree with the Department's recommendation to set the discount rate equal to the weighted average EROAs and to disallow 50 percent of the 2008 market loss for FAS 106 for the same reasons as for the Qualified Pension, as explained above.

Department position: the Company did not show the reasonableness of its position. To treat the 2008 market loss consistently, the Department recommended excluding 50 percent of the 2008 market loss costs from the FAS 106 medical expenses (O&M expense reduction of $88,500). Because the FAS 106 expense is calculated in the same manner as Qualified Pension expense under FAS 87, the Department also recommended that the discount rate for FAS 106 should match the respective EROAs, 7.25 percent for the bargaining employee plan and 6.25 percent for the non-bargaining employee plan, for a weighted average discount rate of 7.11 percent (O&M expense reduction of $1,472,433). The Department proposed a corresponding proportional (54 percent) adjustment to FAS 106 capital costs. In Surrebuttal, the Department accepted the Company's calculation of the revenue requirement effects.

Disputed amount: $1.59 million adjustment and reduction in revenue requirements (both O&M and capital)

Record Citations:
Heuer Rebuttal, Exh. 90 at 21-22
Moeller Direct, Exh. 81 at 12, 114-117, 120-121
Schrubbe Rebuttal, Exh. 83 at 29, 47, 60
Figoli Direct, Exh. 78 at 77-78
Byrne Direct, Exh. 423 at 37-43
Byrne Surrebuttal, Exh. 427 at 12, 22-24, 28-29
Byrne Opening Statement, Exh. 449 at 1
Evidentiary Hearing Transcript, Vol. 5 at 10-13 (Byrne)
Lusti Direct, Exh. 437 at 20, 37
Lusti Surrebuttal, Exh. 442 at 8

7. Paid Leave / Total Labor (2014)

Disputed between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company requested recovery of $49.906 million in paid leave costs. In its Rebuttal Testimony, the Company explained that paid leave (or paid time-off) is not an independent cost or budget item, but rather a component of the total base labor cost, which is made out of Productive Labor and Non-Productive Labor. The actual amount of paid leave varies depending on how much paid time-off employees take during a year – if they take less time as paid leave than budgeted, the actual paid leave amount is lower but total base labor costs do not change. The Company believed an accurate analysis of budget-to-actual results should focus on the Company's Total Labor expense. The Company's actual Total Labor costs exceeded the budget for the period from 2011 and 2013, and the increases in Nuclear and Business Systems Total Labor costs alone account for virtually all of the Department's proposed adjustment of $5.6 million.

Department position: the Company did not show the reasonableness of its position. The Department pointed out that the Company has over-recovered paid leave expenses in the 2011 ($5.1 million) and 2013 ($4.0 million) rate cases. The Department initially recommended allowing a 3.7 percent increase to the actual 2013 paid leave costs to determine the reasonable test year 2014 amount. In Surrebuttal, the Department modified its position to address total labor costs as recommended by the Company, and recommended a downward adjustment of $5.6 million based on the Company's Total Labor expense. The Department calculated the $5.6 million adjustment by starting with 2012 actual labor expense and allowing an annual increase of 3 percent for 2013 and an additional 3 percent for 2014 (note the labor trend from 2011 to 2012 showed a 3 percent increase). The Department stated that this normalizing approach was reasonable, since the 2013 actual labor costs were abnormally high (12.2 percent increase over 2012 actual labor costs) due to extended nuclear outages as noted by the Company and unusually high number of storms as noted by the Department.

Disputed amount: $5.6 million adjustment and reduction in revenue requirements

Record Citations:
Stitt Direct, Exh. 86 at 37-38
Stitt Rebuttal, Exh. 87 at 1-9
Stitt Opening Statement, Exh. 129 at 1-2
Campbell Direct, Exh. 429 at 95-98, 108-109, 171
Campbell Surrebuttal, Exh. 435 at 69-74
Campbell Opening Statement, Exh. 450 at 4
Evidentiary Hearing Transcript, Vol. 5 at 32-33 (Campbell)
Lusti Direct, Exh. 437 at 42
Lusti Surrebuttal, Exh. 442 at 33

8. Rate Case and Monticello Prudency Review Expense Amortization (2014)

Partly disputed between NSP and the Department. No other party provided testimony on the issue.

NSP position: the Company proposed to amortize the 2014 rate case expense over a two-year period, since it would most likely file its next rate case in 2015, using a 2016 test year. The Company believed that a two-year amortization period is appropriate also for the Monticello prudence review costs. These are one-time expenses that should not be considered as capital costs since they do not add to plant in service, do not affect the plant operations in any way, and are not large enough to amortize over a longer time period. It would be inappropriate to require recovery of these costs over a 16.8-year period without a return on the asset.

Department position: the Company did not show the reasonableness of its position. The Department agreed on the amount of rate case and prudence expenses that the Company requested to recover. It also agreed on the two-year amortization period for the rate case expenses. The Department opposed the two-year amortization period for prudence review expenses and stated that these costs should be spread over the remaining life of the Monticello facility, which is 16.8 years, without a return. The Commission is reviewing the prudency of planning and constructing the facility, and the decision will continue for the life of the facility, not until the next rate case is filed as is the case with rate case expenses.

Disputed amount: $418,452 adjustment and reduction in revenue requirements.

Record Citations:
Heuer Direct, Exh. 88 at 142-143
Heuer Rebuttal, Exh. 90 at 23-25
Lusti Direct, Exh. 437 at 27-29
Lusti Surrebuttal, Exh. 442 at 16-18
Lusti Opening Statement, Exh. 451 at 1

9. MYRP: Rate Moderation Proposal – TDG Theoretical Depreciation Reserve Surplus (2014 and 2015 Step)[1]

Disputed among NSP, the Department, and OAG. No other party provided testimony on this issue.

NSP position: in the Company's last rate case, the Commission required amortization over eight years of the difference between the Company's recorded book depreciation reserve and the theoretical book reserve for the transmission, distribution, and general (TDG) assets. In this case, the Company proposed to accelerate return of the remaining theoretical depreciation reserve surplus to customers by amortizing it over the next three years: 50 percent in 2014, 30 percent in 2015, and 20 percent in 2016. The Company believed that its recommendation of using the theoretical reserve surplus in conjunction with the Department of Energy (DOE) settlement payment moderation proposal creates greater consistency and predictability in year-over-year increases in customer rates.

Department position: the Department recommended to return the remaining depreciation reserve surplus to customers by amortizing it over the next three years: 50 percent in 2014, 40 percent in 2015, and 10 percent in 2016, which would result in a $12.633 increase in revenues for 2015 and decrease in revenue requirements. Alternatively, the Department supported the Company's proposed 50-30-20 percent option, which would have a $0 impact. The Department noted that it did not support the give back of theoretical depreciation reserves in the last rate case and fundamentally does not support theoretical depreciation. However, in light of the Commission approval of the give back of theoretical depreciation reserve in the last rate case for transmission, distribution and general plant (using an eight year straight-line method), and the fact that the Commission approved in interim rates for this rate case the Company's give back proposal of 50 percent in 2014, 30 percent in 2015, and 20 percent in 2016, the Department's options for this rate case were limited unless the Department wanted to increase customers rates.

OAG position: the OAG believed that the Company's moderation proposal does not offer any real savings to customers, but simply shifts cost recovery into the future, which will result in higher costs later for future ratepayers. In addition, the moderation proposal violates the Commission's rules that require straight-line depreciation, and therefore requires a variance. The OAG recommended that the Commission should deny the change in the amortization of the depreciation reserve surplus proposed by the Company.

Disputed amount: see Heuer Rebuttal, Schedule 15 for revenue requirement comparisons. No impact for the Company's proposal (or Department's alternative proposal), except $10.1 million corrected DOE amount noted on issue no. 34 below. The Department's initial recommendation is a $12.633 million decrease in revenue requirements.

Record Citations:
Sparby Rebuttal, Exh. 26 at 12-13
Clark Direct, Exh. 99 at 27-29
Clark Rebuttal, Exh. 100 at 36-42
Heuer Direct, Exh. 88 at 8, 92-93, 154-155

---

[1] The rate moderation proposal regarding DOE Settlement Funds is discussed under issue no. 34 and Nuclear Theoretical Depreciation Reserve is discussed under issue no. 75.

Heuer Rebuttal, Exh. 90 at 28-29
Robinson Direct, Exh. 95 at 29-33
Robinson Rebuttal, Exh. 97 at 11-19
Robinson Opening Statement, Exh. 132 at 1
Evidentiary Hearing Transcript, Vol. 2 at 96, 108-110 (Robinson)
Perkett Direct, Exh. 92 at 36-40
Campbell Direct, Exh. 429 at 75-94, 88-90
Campbell Surrebuttal, Exh. 435 at 65-69
Campbell Opening Statement, Exh. 450 at 3-4
Lindell Direct, Exh. 370 at 11-16
Lindell Opening Statement, Exh. 141 at 1-2
Evidentiary Hearing Transcript, Vol. 3 at 190-192 (Lindell)

10. Depreciation and Plant Retirements in the 2015 Step – Passage of Time (2015 Step)

Disputed between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company did not believe a passage of time adjustment is appropriate or necessary in this case. The Company included a limited number of capital projects in the 2015 Step, and excluded a substantial number of other capital projects as well as most O&M items. The Department's recommendation expands the scope of the 2015 Step to cover rate base components and expenses that are decreasing without recognizing that other increasing costs are not included in the Step, which makes the recommendation asymmetrical. The Company also believed that the depreciation adjustment of $17.53 million recommended by the Department does not include both accumulated depreciation reserve and depreciation expenses. When both values are used, the total adjustment would increase the revenue requirements by $1.9 million. Similarly, if forecasted retirements for non-Step projects are accounted for in the 2015 Step revenue requirements calculations, then the annualized plant depreciation expense for all of the 2014 plant additions should be included as well.

Department position: the Company did not show the reasonableness of its position. The Department believed it is appropriate to reflect total plant depreciation expense and related accumulated depreciation for the passage of time from 2014 to 2015 for those projects that are not included in the 2015 Step (but are included in the 2014 test year). Similarly, 2015 plant retirements should be accounted for in the 2015 Step. These are known and measurable changes that decrease expenses, and the language in the Commission's Order in the Multi-Year Rate Plan Docket supports these adjustments that are capital and capital related adjustments. Depreciation is the actual capital investment being spread over the life of the facilities. The Department stated it is unfair and inequitable to allow the Company to reflect a nearly $70 million revenue requirement increase for 36 capital projects (which represent 81.3 percent of all possible 2015 capital projects and 72.4 percent of the 2015 Step) and related depreciation expenses in the 2015 Step without reflecting the Company's reduced total plant depreciation expense, related accumulated depreciation, and plant retirements for the passage of time from 2014 to 2015 in the 2015 Step. Not capturing the step down in rate base due to the normal passage of time and including know 2015 retirements being paid for by ratepayers via 2014 rate base is one-sided. In addition, the 2015 Step is hardly limited, since the Company captured over 80 percent of the full 2015 forecasted increase in rate base. The Department raised concerns about using 2014 rate base amounts that are generally higher than other years and then adding on top of this the incremental 2015 rate base amounts, where 2015 is already a high rate base year. That approach is like adding two peaks together and asserting the sum of the two peaks is the new peak, even though the first peak declined. The Department also noted that in information request no. 2113 the Department requested the Company to update all depreciation for the passage of time, which would include all changes in depreciation expense and depreciation reserve, as discussed on page 163 and (NAC-32) of Ms. Campbell's Direct Testimony, and is not one-sided as suggested by the Company. The Department stated that the forecasted 2015 transmission and distribution plant retirements reduce the revenue requirements in the 2015 Step by $535,552, and updating depreciation expense and accumulated depreciation reserve for all plant in rate base for 2015 (except for the specific 2015 Step capital projects) reduce the 2015 revenue requirements by $17.53 million. The Department recommended these two adjustments.

Disputed amount: $18.07 million adjustment and reduction in revenue requirements for 2015 Step.

Record Citations:
Sparby Rebuttal, Exh. 26 at 11-12, 14-16
Sparby Opening Statement, Exh. 113 at 2
Evidentiary Hearing Transcript, Vol. 1 at 30, 50-51 (Sparby)
Clark Rebuttal, Exh. 100 at 33-34
Clark Opening Statement, Exh. 134 at 1-2
Evidentiary Hearing Transcript, Vol. 2 at 113-114, 119 (Clark)
Perkett Rebuttal, Exh. 94 at 3-7
Perkett Opening Statement, Exh. 130 at 2
Evidentiary Hearing Transcript, Vol. 2 at 57 (Perkett)
Campbell Direct, Exh. 429 at 156-165, 175-177
Campbell Surrebuttal, Exh. 435 at 109-120
Campbell Opening Statement, Exh. 450 at 10-11
Evidentiary Hearing Transcript, Vol. 5 at 27-28, 45-54, 58-63, 65 (Campbell)
Lusti Direct, Exh. 437 at 48-49
Lusti Surrebuttal, Exh. 442 at 39-40

11. Changes to In-Service Dates for Capital Projects (2014 and 2015 Step)

Disputed between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company did not believe it is appropriate to include an adjustment for changes to the in-service dates for capital projects. In any given year, the Company expects a certain amount of movement in in-service dates, as priorities change, some projects are delayed or cancelled, and other projects emerge. The Company believed the 2014 test year is representative of the projects that will go into service in 2014 and therefore there is no need to adjust for changes to in-service dates for a limited number of individual projects. As it pertains to the 2015 Step, in addition to the reasons discussed above, the Company did not believe an in-service date adjustment is needed since the refund mechanism applicable to MYRP already provides customer protections, and the 2015 Step projects represent a limited percentage of the Company's total 2015 budgeted cost.

Department position: the Company did not show the reasonableness of its position. The Department believed that the most current information for in-service dates for capital projects included in the test year 2014 and 2015 Step should be used to determine reasonable rates. The Department disagreed with the Company that it is appropriate to add new capital projects, like-kind replacements and other replacement projects would justify making no adjustments when in-service dates move outside the test year (49 projects) and Step year (2 projects). Allowing additional capital projects into the rate case at this time would unfairly burden Parties and be against the ALJ's First Prehearing Order, which limits introducing new information to this rate case. The Company has the opportunity to put forth its best case in its initial rate case filing. The Department stated that 49 capital projects included in the 2014 test year and 2 capital projects included in the 2015 Step now have revised in-service dates outside 2014 and 2015, and recommended making corresponding adjustments.

Disputed amount: $2.18 million reduction in revenue requirements for test year 2014; $2.05 million reduction in revenue requirements for 2015 Step.

Record Citations:
Sparby Rebuttal, Exh. 26 at 14-15
Clark Rebuttal, Exh. 100 at 12-19
Perkett Direct, Exh. 92 Schedule 8
Perkett Rebuttal, Exh. 94 at 38-42
Evidentiary Hearing Transcript, Vol. 2 at 72-75 (Perkett)
Stitt Opening Statement, Exh. 129 at 1-2
Evidentiary Hearing Transcript, Vol. 2 at 37-38 (Stitt)
Mills Rebuttal, Exh. 60 at 19-21
O'Connor Rebuttal, Exh. 53 at 46-49
Campbell Direct, Exh. 429 at 150-154, 174
Campbell Rebuttal, Exh. 434 at 102-109
Campbell Opening Statement, Exh. 450 at 8-9
Lusti Surrebuttal, Exh. 442 at 12, 39

B. Resolved Department Issues – Revenue Requirements

12. Capital Structure and Cost of Debt (2014 and 2015 Step)

Resolved between NSP and the Department, disputed by ICI Group. No other party provided testimony on this issue.

The Company and the Department agreed that the Company's capital structure, as updated in Rebuttal Testimony, is reasonable and appropriate for test year 2014 (52.50 percent Equity, 45.60 percent long-term debt, and 1.90 percent short-term debt) and for Step year 2015 (52.50 percent Equity, 45.61 percent long-term debt, and 1.89 percent short-term debt). The Company and the Department also agreed that the updated capital structure and cost of debt (5.52 percent for test year 2014 and 6.06 percent for 2015 Step) should be incorporated into this case. The Company and the Department further agreed that the Company's capital structure is reasonably comparable to the capital structures of comparable companies and is appropriate in light of the Company's levels of infrastructure investments and capital market conditions. The Company and the Department also agreed that NSPM's capital structure is an actual, separate capital structure that is market-based and reflects a separate capital structure in financial reporting and communications with financial markets, and therefore ICI Group's recommendation should be rejected.

ICI Group position: the ICI Group recommended that the Company be allowed to include common equity in its capital structure only up to the actual amounts employed by the parent company Xcel Energy Inc., 47.5 percent in 2014 and 49.0 percent in 2015.

Record Citations:
Heuer Opening Statement, Exh. 140 at 3, 8
Evidentiary Hearing Transcript, Vol. 3 at 141-142, 147 (Heuer)
Tyson Direct, Exh. 30 at 3-6, 26-38, 25-30
Tyson Rebuttal, Exh. 31 at 1-11
Tyson Opening Statement, Exh. 116 at 1
Evidentiary Hearing Transcript, Vol. 1 at 103-105, 124-125
Hevert Direct, Exh. 27 at 53-54
Hevert Rebuttal, Exh. 28 at 3, 8-17
Hevert Opening Statement, Exh. 115 at 1
Evidentiary Hearing Transcript, Vol. 1 at 54 (Hevert)
Amit Direct, Exh. 400 at 44-56
Amit Rebuttal, Exh. 402 at 14-15
Amit Opening Statement, Exh. 443 at 1-2
Evidentiary Hearing Transcript, Vol. 4 at 35-36 (Amit)
Glahn Direct, Exh. 250 at 25-26
Glahn Surrebuttal, Exh. 251 at 5-7

13. Sales Forecast (2014 and 2015 Step)

Resolved among NSP, the Department, and MCC. No other party provided testimony on this issue.

NSP position: in Rebuttal, the Company proposed to use the 2014 weather-normalized actual sales data to establish 2014 test year sales in this proceeding, which would eliminate the need, for example, to determine the appropriate Demand Side Management (DSM) adjustment or customer counts. The Company initially objected to the Department's proposal to also reflect the sales for a new large commercial and industrial customer in 2015 but subsequently agreed to the adjustment for this customer. The Company agreed to use the Department's coefficients to weather-normalize the 2014 test year sales and committed to work with the Department to ensure that the calculations are correct. In case the Commission will not approve the proposal to use actual sales data, the Company recommended adopting its Rebuttal sales forecast, which uses weather-normalized actual sales from January through May 2014 and projections from June through December, including a DSM adjustment. The Company also agreed to work with the Department and other stakeholders on the use of the price variable or other aspects of the sales forecast model in the future.

During the Evidentiary Hearing, the Company proposed to submit the first 11 months of sales data and the related revenue calculations on December 16, 2014 to allow sufficient time for review and comment. The Company proposed to submit the December 2014 actual sales data no later than January 16, 2015. The Company can also submit forecasted December sales data in its December filing, which would then include 11 months of actual sales data and one month of forecasted sales data.

Department position: the Department agreed with the Company's Rebuttal and Evidentiary Hearing proposal to calculate the test year sales based on a full year of 2014 actual, weather-normalized sales data, to include the addition of a new large commercial and industrial customer in 2015, and to use the Department's calculations and coefficients to weather-normalize the test year 2014 sales. If any forecasted data is used for December 2014 sales, the Department recommended using values from its updated forecast, not the Company's. In case the Commission will not approve the use of actual 2014 sales data, the Department recommended using its updated sales forecast for setting final rates. But if the Commission uses the Company's updated sales forecast for setting final rates, the Department recommended using the Company's updated sales forecast as corrected by the Department in Surrebuttal Testimony.

MCC position: during the Evidentiary Hearing, MCC accepted the proposal by the Company and the Department to use the 2014 actual, weather-normalized sales, including the addition of a new large commercial and industrial customer in 2015, to establish 2014 test year sales in this proceeding.

Record Citations:
Heuer Opening Statement, Exh. 140 at 5-6
Evidentiary Hearing Transcript, Vol. 3 at 143-144 (Heuer)
Sparby Rebuttal, Exh. 26 at 19
Marks Direct, Exh. 38 at 1-52
Marks Rebuttal, Exh. 40 at 1-21
Hyde Direct, Exh. 43 at 1-10
Hyde Rebuttal, Exh. 44 at 1-7
Hyde Opening Statement, Exh. 119 at 1-2
Evidentiary Hearing Transcript, Vol. 1 at 168-179 (Hyde)
Sundin Rebuttal, Exh. 42 at 6-15
Sundin Opening Statement, Exh. 118 at 1-2
Evidentiary Hearing Transcript, Vol. 1 at 140-143, 163-164 (Sundin)
Shah Direct, Exh. 404 at 1-31
Shah Surrebuttal, Exh. 406 at 1-21, SS-S-5[2]
Shah Opening Statement, Exh. 444 at 1
Evidentiary Hearing Transcript, Vol. 4 at 51-55 (Shah)
Lusti Direct, Exh. 437 at 43
Lusti Surrebuttal, Exh. 442 33, 44
Evidentiary Hearing Transcript, Vol. 5 at 84-86 (Lusti)
Maini Direct, Exh. 343 at 6-14
Maini Surrebuttal, Exh. 345 at 5-10
Maini Opening Statement, Exh. 145 at 1
Evidentiary Hearing Transcript, Vol. 4 at 11, 13 (Maini)

[2] Attachment SS-S-5 was initially labeled SS-S-1 in Department Exh. 406 (Shah Surrebuttal). The Department corrected this reference at the Evidentiary Hearing.

14. Property Tax Amount (2014)

Resolved between the NSP and the Department. Also MCC provided testimony on this issue.

NSP position: the Company originally requested $149.2 million in property tax expenses for the 2014 test year. In Rebuttal, the Company validated the accuracy of its initial 2014 forecast by using updated information and based on the validated data, expected the 2014 total Company property tax expense to be $145.1 million. During the Evidentiary Hearing, the Company agreed to reduce the 2014 test year property tax amount to $141.0 million (a $9.0 million reduction), as recommended by the Department in Surrebuttal, subject to a true-up for actual 2014 property taxes. Under the true-up proposal, the total 2014 test year property tax would be capped at $145.0 million (Minnesota electric jurisdiction). There is no downward limit on the true-up.

The Company and the Department agreed on the following procedure for the property tax true-up: the Company will file its year-end 2014 property tax expense with the Commission on January 16, 2015, based on Truth in Taxation Notices received in November and December of 2014. The Commission would reflect the 2014 year-end property tax expense in its determination of the Company's 2014 revenue requirement and the 2014 year-end property tax expense would be reflected in final rates in this case, up to a cap of $145.0 million (Minnesota electric jurisdiction). The Company will also make a compliance filing on June 30, 2015 detailing the final 2014 property tax expense reflected on property tax statements received in the spring of 2014. If the 2014 property tax expense reflected on the property tax statements is less than the year-end 2014 property tax expense (i.e., the 2014 test year property tax expense), the Company will make ongoing annual refunds of the difference until the Company files the next rate case.

Department position: the Department initially recommended reducing the 2014 test year property tax expense by 9 percent ($13.5 million). In Surrebuttal, the Department recommended reducing the 2014 test year property tax by $14.0 million, which reflects a test year property tax expense of $136.0 million, based on an average increase of 10.72 percent in property tax expense for each year from 2009 to 2013. Alternatively, the Department recommended a reduction of $9.0 million, based on the percent difference between the Company's initial 2014 test year forecast presented in Direct Testimony and the validated 2014 property tax presented in Rebuttal Testimony and including a further adjustment related to the difference between the Company's June 2013 forecast of 2013 property taxes and actual 2013 property taxes. During the Evidentiary Hearing, the Department accepted the Company's proposal to reduce the 2014 test year property tax amount to $141.0 million, subject to a true-up for actual 2014 property taxes and a cap of $145.0 million.

MCC position: MCC believed that the most current information available, as provided in IR MCC-248, should be used to estimate the property tax amount, resulting in an adjustment of $5.9 million. Alternatively, MCC accepted the Department's proposal presented in Direct Testimony.

Adjustment: $9.0 million reduction in revenue requirements, subject to true-up, with ultimate expense capped at $145.0 million.

Record Citations:
Heuer Opening Statement, Exh. 140 at 2
Evidentiary Hearing Transcript, Vol. 3 at 140, 161-164, 168-169 (Heuer)

Duevel Direct, Exh. 32 at 1-2, 5-14
Duevel Rebuttal, Exh. 34 at 2-11
Duevel Opening Statement, Exh. 117 at 1
Evidentiary Hearing Transcript, Vol. 1 at 136-139 (Duevel)
Lusti Direct, Exh. 437 at 36
Lusti Surrebuttal, Exh. 442 at 24-30
Lusti Opening Statement, Exh. 451 at 2
Evidentiary Hearing Transcript, Vol. 5 at 75-76 (Lusti)
Schedin Direct, Exh. 340 at 21-22
Schedin Surrebuttal, Exh. 342 at 11-12

15. Emissions Control Chemical Costs (2014)

Resolved between NSP and the Department. No other party provided testimony on this issue.

NSP position: in its initial filing, the Company requested recovery of approximately $10.30 million for emissions control chemical costs for the test year (Minnesota electric jurisdiction). The Company believed its 2014 test year budget for emissions control chemicals is reasonable, based on appropriate factors, and responsive to similar concerns raised by the Department in the last rate case. During the Evidentiary Hearing, the Company accepted the Department's recommended downward adjustment of $2.265 million for chemical costs.

Department position: the Department noted that the Company has over-recovered emissions control chemical costs each year since 2009, and believed that using historical averages of the Company's actual emission chemical costs provides more accurate results than the Company's forecasts. The Department recommended using a three-year historical average of prior emissions costs (adjusted for Sherco 3 outage and upcoming chemical use at Sherco 1 and 2) and proposed a downward adjustment of $2.265 million for the Minnesota electric jurisdiction ($1.876 million for other than Sherco chemical costs and $0.389 million for Sherco chemical costs).

Adjustment: $2.265 million reduction in revenue requirements.

Record Citations:
Heuer Opening Statement, Exh. 140 at 1
Evidentiary Hearing Transcript, Vol. 3 at 140 (Heuer)
Mills Direct, Exh. 58 at 16-29
Mills Rebuttal, Exh. 60 at 3-10
Mills Opening Statement, Exh. 125 at 1
Evidentiary Hearing Transcript, Vol. 2 at 11-12 (Mills)
Robinson Rebuttal, Exh. 97 at 25
Campbell Direct, Exh. 429 at 10-26, 165-166
Campbell Surrebuttal, Exh. 435 at 21-28
Campbell Opening Statement, Exh. 450 at 2
Lusti Direct, Exh. 437 at 40
Lusti Surrebuttal, Exh. 442 at 32

16. Insurance – Surplus Distributions from Industry Mutual Insurance Pools (2014)

Resolved between NSP and the Department. No other party provided testimony on the issue.

NSP position: the Company did not include the Nuclear Electric Insurance Limited (NEIL) and Energy Insurance Mutual (EIM) surplus distributions in the 2014 test year in its initial filing. In Rebuttal, the Company agreed that it is appropriate to include these distributions as an offset to the 2014 test year budget.

Department position: the Department listed several reasons why it believed it is unreasonable to exclude the NEIL and EIM surplus distributions form the 2014 test year and recommended a corresponding adjustment.

Adjustment: $1.662 million reduction in revenue requirements.

Record Citations:
Heuer Rebuttal, Exh. 90 at 12-13
Anderson Direct, Exh. 35 at 14-18
Anderson Rebuttal, Exh. 37 at 2-3
Byrne Direct, Exh. 423 at 22-27
Byrne Surrebuttal, Exh. 427 at 11
Lusti Direct, Exh. 437 at 39
Lusti Surrebuttal, Exh. 442 at 32

17. Treatment of Capitalized Pension and Related Benefit Costs – Rate Base Factor Method (2014)

Resolved between NSP and the Department. No other party provided testimony on this issue.

The Company proposed to use the method developed in the last rate case to determine pension and related benefit O&M expenses. This method applies a rate base factor to the beginning-of-year/end-of-year average of the capitalized portion of costs and thus converts the capital adjustments to revenue requirement. The Department accepted the Company's proposal.

Record Citations:
Heuer Rebuttal, Exh. 90 at 18-20
Campbell Surrebuttal, Exh. 435 at 74-75

18. Qualified Pension – Measurement Date Update (2014)

Resolved between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company believed that the same measurement date should be used to calculate all pension and benefit expenses, including qualified pension. The Company recommended using December 31, 2013 as the measurement date because it provides the most current information available.

Department position: the Department did not initially accept the Company's proposal to update the measurement date for the qualified pension because the Company had not initially supported the increase in pension expense due to "unfavorable demographic experience" and the lower 7.01 percent actual return on assets compare to the 7.25 percent EROA for 2013. Additionally, the increased pension expense was unexpected due to how well the financial market performed in 2013. In Surrebuttal, the Department accepted the Company's proposal to update the measurement date for the qualified pension to December 31, 2013.

Adjustment: $1.011 million increase in revenue requirements (both O&M and capital).

<u>Record Citations:</u>
Heuer Rebuttal, Exh. 90 at 19-20
Schrubbe Rebuttal, Exh. 83 at 8-15
Tyson Rebuttal, Exh. 31 at 15-21
Campbell Direct, Exh. 429 at 120-124, 172
Campbell Surrebuttal, Exh. 435 at 87-89
Campbell Opening Statement, Exh. 450 at 5
Lusti Surrebuttal, Exh. 442 at 11-12

19. Retiree Medical Expenses (FAS 106) – Measurement Date Update (2014)

Resolved between NSP and the Department. No other party provided testimony on this issue.

The Company and the Department agreed to update the measurement date for FAS 106 to December 31, 2013.

Adjustment: $666,522 reduction in revenue requirements.

Record Citations:
Heuer Rebuttal, Exh. 90 at 21-22
Schrubbe Rebuttal, Exh. 83 at 8-11, 60
Byrne Direct, Exh. 423 at 40-41, 43
Byrne Surrebuttal, Exh. 427 at 11-12
Byrne Opening Statement, Exh. 449 at 1

20. Non-Qualified Pension – Restoration Plan (2014)

Resolved between NSP and the Department. No other party provided testimony on the issue.

NSP position: the Company explained that its Restoration Plan provides supplemental benefits to those employees whose wages exceed the IRS-determined compensation limits in order to give them equal level of benefits than those employees who can participate in qualified pension plans. Restoration Plans are a common practice in the electric industry and other American businesses. In Rebuttal, the Company accepted the Department's recommendation to disallow Restoration Plan costs for this case.

Department position: the Department recommended that the Commission disallow all Restoration Plan costs because it is not reasonable for ratepayers to finance these benefits. The Company's Restoration Plan provides a generous tax benefit, which exceeds the amounts allowed by the Internal Revenue Service, to employees who are already highly compensated. Also, the Commission has disallowed the recovery of non-qualified and supplemental pension costs in recent rate cases.

Adjustment: $704,000 reduction in revenue requirements (both O&M and capital).

Record Citations:
Heuer Direct, Exh. 88 at 142
Heuer Rebuttal, Exh. 90 at 21
Moeller Direct, Exh. 81 at 12, 108-113
Figoli Direct, Exh. 78 at 73-76
Figoli Rebuttal, Exh. 80 at 13-17
Campbell Direct, Exh. 429 at 105-110, 136-145, 174
Campbell Surrebuttal, Exh. 435 at 12-14
Campbell Opening Statement, Exh. 450 at 1
Lusti Direct, Exh. 437 at 41
Lusti Surrebuttal, Exh. 442 at 11-12

21. Post-Employment Benefits – Long-Term Disability and Workers' Compensation (FAS 112) (2014)

Resolved between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company requested recovery of $3.79 million in O&M expenses and $190,152 in capital costs related to post-employment benefits (primarily long-term disability and workers' compensation) for former or inactive employees after employment but before retirement. In Rebuttal, the Company agreed on the Department's recommendation to update the measurement date to December 31, 2013.

Department position: the Department agreed on the Company's proposed discount rate of 3.74 percent and recommended updating the measurement date to December 31, 2013. In Surrebuttal, the Department accepted the Company's calculation of the revenue requirement effects.

Adjustment: $421,463 reduction in revenue requirements (both O&M and capital).

Record Citations:
Heuer Rebuttal, Exh. 90 at 22-23
Moeller Direct, Exh. 81 at 12, 117-121
Schrubbe Rebuttal, Exh. 83 at 60
Byrne Direct, Exh. 423 at 43-47
Byrne Surrebuttal, Exh. 427 at 13
Lusti Direct, Exh. 437 at 37
Lusti Surrebuttal, Exh. 442 at 8-9

22. Active Health Care and Welfare Costs (2014)

Resolved between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company believed its method of calculating active health care and welfare costs is appropriate and the costs are reasonable and representative of the test year 2014. The calculations were based on the 2011 and 2012 actual health and welfare costs, adjusted for plan changes, inflation, and claim trends. During the Evidentiary Hearing, the Company accepted the Department's downward adjustment of $1.082 million.

Department position: the Department recommended adjusting the active health care expenses because the Company has over-recovered health care costs in the recent past and because other factors indicated that health care costs would not increase as much as the Company had forecasted in its 2014 test year. The Department initially recommended using a three-year average of 2011-2013 actual health care costs to calculate the 2014 test year amount, and a corresponding proportional (9.1 percent) adjustment to all health care and welfare capital costs. In Surrebuttal, the Department modified its recommendation to use an inflation factor of 2.85 percent over 2013 claims expenses, which resulted in a total expense of $35.387 million and a corresponding proportional adjustment in capital costs. The Department also requested that in its next rate case filing, the Company is required to provide historical active health care costs since 2011 for each calendar year, including both book and claims expenses and Incurred But Not Reported (IBR) accruals and reversals.

Adjustment: $1.082 million reduction in revenue requirements (both O&M and capital)

Record Citations:
Heuer Opening Statement, Exh. 140 at 2
Evidentiary Hearing Transcript, Vol. 3 at 140-141 (Heuer)
Moeller Direct, Exh. 81 at 112, 128-134
Schrubbe Rebuttal, Exh. 83 at 47-60
Evidentiary Hearing Transcript, Vol. 2 at 12 (Mills)
Schrubbe Opening Statement, Exh. 126 at 1
Evidentiary Hearing Transcript, Vol. 2 at 18 (Schrubbe)
Figoli Direct, Exh. 78 at 57-65
Byrne Direct, Exh. 423 at 27-37
Byrne Surrebuttal, Exh. 427 at 13-21, 27-28
Byrne Opening Statement, Exh. 449 at 3
Evidentiary Hearing Transcript, Vol. 5 at 9 (Byrne)
Lusti Direct, Exh. 437 at 38
Lusti Surrebuttal, Exh. 442 at 9

23. Nuclear Cash-Based Retention Program (2014)

Resolved between NSP and the Department. No other party provided testimony on the issue.

NSP position: the Company stated that the Nuclear Cash-Based Retention Program is a vital program necessary to attract new employees and to retain current employees in highly specialized and critical positions in the competitive nuclear labor market. The Company also explained that the retention program and Annual Incentive Plan (AIP) serve different purposes and provide separate compensation for different goals and time periods. During the Evidentiary Hearing, the Company accepted the Department's proposal to remove all the costs associated with the Nuclear Retention Program from the test year.

Department position: the Department stated it is reasonable to conclude that the Nuclear Retention Program was created in 2012 to provide some of the Company's nuclear employees additional compensation to replace amounts they would likely not receive via the traditional incentive compensation (the AIP), until such time as the nuclear business unit as a whole could achieve a high Key Performance Indicator (KPI) rating.

Adjustment: $516,466 reduction in revenue requirements.

Record Citations:
Heuer Opening Statement, Exh. 140 at 2
Evidentiary Hearing Transcript, Vol. 3 at 141 (Heuer)
Figoli Direct, Exh. 78 at 50-55
Figoli Rebuttal, Exh. 80 at 10-13
O'Connor Direct, Exh. 51 at 99-105
O'Connor Rebuttal, Exh. 53 at 19-29
O'Connor Opening Statement, Exh. 123 at 1-2
Evidentiary Hearing Transcript, Vol. 1 at 218 (O'Connor)
Lusti Direct, Exh. 437 at 29-35
Lusti Surrebuttal, Exh. 442 at 19-24

24. Customer Care O&M Expenses – Miscellaneous O&M Credits (2014)

Resolved between NSP and the Department. No other party provided testimony on the issue.

NSP position: the Company accepted the Department's recommendation that the Miscellaneous O&M Credits be set at $1.216 million, because this amount closely correlates with the Company's current budget forecast for 2014. The Company did not believe that the use of historical average is appropriate for this type of expense.

Department position: the Department pointed out that the Company has over-recovered Customer Care O&M expenses by $3.2 million from 2011 to 2013. Almost half of this is accounted by the Meter Reading O&M and specifically under-estimation of the Miscellaneous O&M Credits. Based on information provided regarding the Company's contract with Cellnet, the Department recommended that the Company's 2014 test year Miscellaneous O&M Credits to be set at the amount of the average Miscellaneous O&M Credits from 2010 through 2013, at $1.216 million.

Adjustment: $503,142 reduction in revenue requirements.

Record Citations:
Heuer Rebuttal, Exh. 90 at 12
Gersack Direct, Exh. 71 at 10, 16-17
Gersack Rebuttal, Exh. 72 at 1-6

Byrne Direct, Exh. 423 at 10-17, 49
Byrne Surrebuttal, Exh. 427 at 5-7
Lusti Direct, Exh. 437 at 38
Lusti Surrebuttal, Exh. 442 at 31

25. Nuclear Fees (2014)

Resolved between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company disagreed with the Department's original recommendation to allow only a 1.1 percent increase in nuclear fees from 2013, because the Department used the abnormally low 2013 Nuclear Regulatory Commission (NRC) actual fees for the starting point and because all other than NRC fees increased about 10 percent from 2011 to 2013. The Company also explained that in June 2014, the NRC updated the pre-reactor portion of its 2014 Annual Fee at 19 percent higher than in 2013 ($15.8 million). This increase alone justifies the Company's test year 2014 nuclear fee amount. During the Evidentiary Hearing, the Company agreed to reduce the amount of other than NRC nuclear fees and accepted the Department's final recommended adjustment of $1.00 million.

Department position: the Department recommended that the 2014 test year nuclear fees should be reduced because the average year-to-year increase in nuclear fees has been 1.1 percent from 2011 to 2013. In Surrebuttal, the Department agreed with the Company on the NRC fees based on the 2014 final fee rule by NRC which significantly increased nuclear fees by over 19 percent and recommended allowing the requested amount of $15.00 million for the Minnesota jurisdiction. However, the Department continued to believe that many of the other nuclear fees were overstated, and recommend a $1.00 million downward adjustment to other nuclear fees.

Adjustment: $1.00 million reduction in revenue requirements

Record Citations:
Heuer Rebuttal, Exh. 90 at 27-28
Heuer Opening Statement, Exh. 140 at 2
Evidentiary Hearing Transcript, Vol. 3 at 140 (Heuer)
O'Connor Direct, Exh. 51 at 112-117
O'Connor Rebuttal, Exh. 53 at 29-41
O'Connor Opening Statement, Exh. 123 at 1-2
Evidentiary Hearing Transcript, Vol. 1 at 218 (O'Connor)
Campbell Direct, Exh. 429 at 67-75, 170
Campbell Surrebuttal, Exh. 435 at 59-65
Campbell Opening Statement, Exh. 450 at 2
Lusti Direct, Exh. 437 at 42
Lusti Surrebuttal, Exh. 442 at 32

26. Investor Relations Costs (2014)

Resolved between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company requested recovery of 50 percent of investor relations costs with the exception of requesting recovery for all stock registration fees for the Minnesota electric jurisdiction. The Company believed that this request accommodated concerns expressed in the prior rate cases. In Rebuttal, the Company accepted the Department's recommendation to remove 50 percent of all investor relations expenses, including the stock registration fees.

Department position: the Department stated that the Company's request does not comply with the Commission's Order in the last rate case, which excluded 50 percent of all investor relations expenses from the test year. The Department recommended that 50 percent of the entire amount of investor relations costs, including the stock registration fees, be removed from the test year.

Adjustment: $78,140 reduction in revenue requirements.

Record Citations:
Heuer Direct, Exh. 88 at 139
Heuer Rebuttal, Exh. 90 at 13
Stitt Direct, Exh. 86 at 60-61
Tyson Direct, Exh. 30 at 38-44
Tyson Rebuttal, Exh. 31 at 30
Byrne Direct, Exh. 423 at 7-10, 48-49
Byrne Surrebuttal, Exh. 427 at 4-5
Lusti Direct, Exh. 437 at 38
Lusti Surrebuttal, Exh. 442 at 31

27. Nuclear Refueling Outage Cost Amortization (2015 Step)

Resolved between NSP and the Department; disputed between NSP and OAG. No other party provided testimony on this issue.

NSP position: the Company believed an adjustment for decreased nuclear outage costs in the 2015 Step is unnecessary and inappropriate. The Company included a limited number of capital projects in the 2015 Step, and excluded a substantial number of other capital projects as well as most O&M items. The OAG recommendation also expands the scope of the 2015 Step to cover rate base components and expenses that are decreasing without recognizing that other increasing costs are not included in the Step. The Company also pointed out that nuclear amortization expense is a separate O&M item, which is not directly related to any of the capital projects included in the 2015 Step.

Department position: the Department noted in its Direct Testimony that the amortization expenses for nuclear refueling outages decreased by $7.5 million from 2014 to 2015, yet the Company did not include this reduction in the 2015 Step to benefit the ratepayers. The Department stated that a corresponding downward adjustment ($5.5 million for the Minnesota electric jurisdiction) is reasonable to balance the representation of the 2015 costs of the nuclear facilities and to account for known and measurable decreases in expenses (in contrast to only increases). In Surrebuttal, the Department agreed that nuclear outage costs related to O&M fuel outage expenses (for which the Company received special approval so they could amortize these expenses between fuel outages in Docket No. E002/M-07-1489) are not capital costs, as initially believed in Direct Testimony. As a result, the Department no longer recommended the $5.5 million adjustment for nuclear outage expenses.

OAG position: the OAG supported the original recommendation and arguments made by the Department in its Direct Testimony. The OAG also stated that the nuclear refueling outage expense is a known and measurable decrease, and it should not be treated differently because of MYRP.

Disputed amount: $5.5 million adjustment and reduction in revenue requirements for 2015 Step (OAG Recommendation).

Record Citations:
Sparby Rebuttal, Exh. 26 at 11-12
Clark Rebuttal, Exh. 100 34-35
Clark Surrebuttal, Exh. 101 at 3-6
O'Connor Direct, Exh. 51 at 118-127
O'Connor Surrebuttal, Exh. 55 at 2-3
Campbell Direct, Exh. 429 at 61-67, 169-170
Campbell Surrebuttal, Exh. 435 at 14-17
Campbell Opening Statement, Exh. 450 at 1
Lusti Direct, Exh. 437 at 53
Lusti Surrebuttal, Exh. 442 at 43
Lindell Rebuttal, Exh. 372 at 5-6
Lindell Opening Statement, Exh. 141 at 2
Evidentiary Hearing Transcript, Vol. 3 at 194-195 (Lindell)

28. Business Systems General Ledger (G/L) System (2015 Step)

Resolved between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company stated it is on track with the G/L project milestones and confident that it can meet the cutover deadline December 31, 2015, when the G/L system will be placed in service and used for its intended purpose. The Company decided to designate December 31, 2015 as the official cutover to the new G/L system to align with the Company's financial year-end date. The Company also explained that the new G/L system will be operationally ready on November 1, 2015 and be used parallel with the JDE system in November and December 2015. During the parallel operation, the new G/L system has completed all testing and is processing live financial transactions, running reports, and executing business processes.

Department position: the Department initially recommended removing the G/L replacement project costs ($20.36 million) from the 2015 Step. The Department stated the Company has not shown that the system will be used and useful for Minnesota ratepayers until January 1, 2016, because the G/L system will be in a testing environment in the fourth quarter of 2015 and will not be placed into service until the last day of 2015. In Surrebuttal, the Department agreed that the G/L system will be in service on December 31, 2015 and no longer recommended the adjustment.

Record Citations:
Harkness Direct, Exh. 62 at 48-52

Harkness Rebuttal, Exh. 64 at 1-12
Perkett Rebuttal, Exh. 94 at 50-51
Robinson Rebuttal, Exh. 97 at 8
Byrne Direct, Exh. 423 at 18-22
Byrne Surrebuttal, Exh. 427 at 7-10
Campbell Direct, Exh. 429 at 154
Lusti Direct, Exh. 437 at 47
Lusti Surrebuttal, Exh. 442 at 38

29. Prairie Island Site Administration Building (2015 Step)

Resolved between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company believed that any adjustments to the Prairie Island administrative building project costs or in-service date were unnecessary. The Company included $22.6 million (Total Company) for the Prairie Island administration building capital costs in the 2015 Step, however, this amount covered also other additional work that was not included in the scope of the competitive bid. The Company explained that it expects to receive the certificate of occupancy in December 2014, and from that day the building will be used and useful. Also the gradual move-in process is planned to begin in December 2014.

Department position: in Direct, the Department noted that the total amount of $22.6 million for the Prairie Island administrative building project is more than the competitive bid that was selected, and the Company has not provided support for the amount that exceeds the selected bid. The Department also recommended changing the in-service date from December 31, 2014 to March 1, 2015, since the Company will complete punch list items in January 2015 and plans to move the staff to the new building in March 2015. In Surrebuttal, the Department agreed with the Company because the Company supported the additional costs and the Company indicated that it would now be moving some employees into the building in December 2014. Therefore, the Department no longer recommended the downward capital cost adjustment or the change in the in-service date for the PI administrative building.

Record Citations:
O'Connor Direct, Exh. 51 at 69-70
O'Connor Rebuttal, Exh. 53 at 42-44
O'Connor Opening Statement, Exh. 123 at 1
Perkett Rebuttal, Exh. 94 at 48-50
Robinson Direct, Exh. 95 at 8-11
Robinson Rebuttal, Exh. 97 at 8
Campbell Direct, Exh. 429 at 154-156
Campbell Surrebuttal, Exh. 435 at 17-20
Campbell Opening Statement, Exh. 450 at 2
Lusti Direct, Exh. 437 at 49
Lusti Surrebuttal, Exh. 442 at 10, 41

30. Pleasant Valley Wind and Border Winds (2015 Step)
31. Ratepayer Protection Mechanism for Company-Owned Wind Farm Costs

Resolved between NSP and the Department. Also the OAG and MCC provided testimony on this issue.

NSP position: the Company accepted the Department's recommendation that the base rates for the 2015 Step should include estimated Production Tax Credits (PTCs), subject to true-up in the RES Rider. However, the Company was also open to include both the capital costs and PTCs for Pleasant Valley and Border Winds in the Renewable Energy Standard (RES) Rider. The Company clarified that the difference between the capital expenditure numbers in Mr. Mill's and Mr. Robinson's testimonies was due to AFUDC and the Strategist modeling in the Wind Acquisition Dockets included AFUDC. The Company stated that MCC's proposal to limit recovery to 1-2 months does not reflect how rate base is calculated using beginning of year/end of year averages. In addition, the methodology used should be consistent for all capital additions calculations. Given the limited time, the Company believed that this case is not the best forum to develop a ratepayer protection mechanism for Company-owned wind farm costs, and proposed to work with MCC and other Parties prior to January 1, 2015 and report results in the RES Rider Docket.

Department position: the Department originally stated that the Company has not shown why it is reasonable to recover capital costs for the Pleasant Valley and Border Winds projects in excess of the amounts that were approved in the Wind Acquisition Dockets and believed that the costs were overstated in the 2015 Step. In Surrebuttal, the Department accepted the Company's explanation of discrepancies between Mr. Mills' testimony and Mr. Robinson's testimony due to AFUDC (since the AFUDC was included in the strategist model, which was approved by the Commission) and no longer proposed a downward adjustment of $5,672,482 for capital project costs. The Department recommended that the base rates for the 2015 Step should include estimated PTCs ($11.093 million), subject to true-up in the RES Rider. The Department stated it would prefer to include the recovery of the capital costs in this rate case, but did not oppose to recover them in the RES Rider, particularly if the Company will not otherwise increase rates in 2016.

OAG position: the OAG supported the original arguments and recommendations made by the Department in its Direct Testimony, including the downward adjustment of $5,672,482 and treatment of PTCs.

MCC position: MCC stated its concern of the in-service dates for the Pleasant Valley Wind and Border Winds projects, which will be late in 2015. MCC initially recommended removing all the capital costs related to these two wind projects from the 2015 Step, alternatively, the Commission should limit recovery to only those 1-2 months that the projects will be in service in 2015. In Surrebuttal, MCC recommended that the Company should recover the costs for the two wind projects through the RES Rider and supported the Company's proposal to work with MCC and other Parties regarding a ratepayer protection mechanism that addresses cost overruns for Company-owned wind farms. MCC recommended that the Commission include an Order point with a process and timeline regarding the ratepayer protection mechanism, so that interested Parties may participate on a timely basis.

Disputed amount: $5,672,482 million reduction in revenue requirements (OAG Recommendation).

Record Citations:
Sparby Rebuttal, Exh. 26 at 20
Clark Rebuttal, Exh. 100 at 26-29
Mills Direct, Exh. 58 at 61-66
Mills Rebuttal, Exh. 60 at 11-15
Robinson Direct, Exh. 95 at 11-13, 37-38
Robinson Rebuttal, Exh. 97 at 3-7
Robinson Opening Statement, Exh. 132 at 1-2
Evidentiary Hearing Transcript, Vol. 2 at 96 (Perkett)
Perkett Rebuttal, Exh. 94 at 52-53
Campbell Direct, Exh. 429 at 32-42
Campbell Surrebuttal, Exh. 435 at 2-12
Campbell Opening Statement, Exh. 450 at 1
Lusti Direct, Exh. 437 at 47, 51
Lusti Surrebuttal, Exh. 442 at 39
Lindell Rebuttal, Exh. 372 at 3-5
Maini Direct, Exh. 343 at 2-6
Maini Surrebuttal, Exh. 345 at 1-4
Evidentiary Hearing Transcript, Vol. 4 at 13-16, 19-22 (Maini)

32. Property Tax Amount (2015 Step)

Resolved between NSP and the Department. No other party provided testimony on this issue.

NSP position: in Rebuttal, the Company proposed to include in the 2015 Step only those property tax expenses that are directly associated with the capital projects in the 2015 Step. This resulted in a $3.309 million adjustment and reduction in the revenue requirements.

Department position: the Department recommended reducing the 2015 Step property tax expense by 9 percent to reflect the cumulative difference between the Company's actual property taxes and the amounts included in rates over a thirteen-year period. In Surrebuttal, the Department accepted the $3.309 million adjustment proposed by the Company.
Adjustment: $3.309 million reduction in revenue requirements.

Record Citations:
Heuer Rebuttal, Exh. 90 at 29
Clark Rebuttal, Exh. 100 at 9
Robinson Direct, Exh. 95 at 23-25
Robinson Rebuttal, Exh. 97 at 8-10
Duevel Direct, Exh. 32 at 3-5, 15-18
Duevel Rebuttal, Exh. 34 at 12-13
Lusti Direct, Exh. 437 at 36, 54
Lusti Surrebuttal, Exh. 442 at 45

33. Emissions Control Chemical Costs (2015 Step)

Resolved between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company believed its mercury sorbent budget in the 2015 Step is based upon the best information available, however, the Company acknowledged that there is some uncertainty around estimating the use of mercury sorbent at Sherco Units 1 and 2. In Rebuttal, the Company agreed that non-capital costs in the 2015 Step should be directly related to capital projects and agreed to remove chemical costs associated with A.S. King and Sherco Unit 3 from the 2015 Step ($180,000 adjustment). During the Evidentiary Hearing, the Company agreed to further reduce the amount of chemical costs and remove an additional $1.40 million, resulting in a total adjustment of $1.58 million.

Department position: the Department originally recommended excluding half of the 2015 emissions control chemical costs ($2.98 million for the Minnesota electric jurisdiction). The Department stated that the Company has a pattern of over-estimating emissions control chemical costs, and there is added uncertainty because the use of mercury sorbent at Sherco 1 and 2 will be a new experience for the Company. In addition, the Department noted that the chemical costs associated with A.S. King and Sherco Unit 3 are not directly related to new capital upgrades and therefore should not be included in the 2015 Step. During the Evidentiary Hearing, the Department accepted the final $1.58 million adjustment proposed by the Company.

Adjustment: $1.58 million reduction in revenue requirements.

Record Citations:
Heuer Opening Statement, Exh. 140 at 7
Evidentiary Hearing Transcript, Vol. 3 at 146-147 (Heuer)
Sparby Rebuttal, Exh. 26 at 12, 20-21
Clark Direct, Exh. 99 at 16-17
Clark Rebuttal, Exh. 100 at 9, 30-32
Mills Direct, Exh. 58 at 39-40
Mills Rebuttal, Exh. 60 at 3-10
Mills Opening Statement, Exh. 125 at 1
Evidentiary Hearing Transcript, Vol. 2 at 12 (Mills)
Robinson Direct, Exh. 95 at 27-28, Schedule 12.
Robinson Rebuttal, Exh. 97 at 8-10
Campbell Direct, Exh. 429 at 26-32, 166
Campbell Surrebuttal, Exh. 435 at 28-31
Campbell Opening Statement, Exh. 450 at 2
Lusti Direct, Exh. 437 at 53
Lusti Surrebuttal, Exh. 442 at 44

34. MYRP: Rate Moderation Proposal – DOE Settlement Funds (2015 Step)

Resolved between NSP and the Department, disputed by OAG and Commercial Group. No other party provided testimony on this issue.

NSP position: the Company proposed to use the DOE settlement funds received in 2013 and 2014 in excess of the annual decommissioning accrual requirements as a moderation mechanism to reduce the 2015 revenue deficiency. The Company agreed with the adjustment proposed by the Department and stated that the current amount of DOE settlement payments available for rate moderation is approximately $25.74 million. The Company believed that its recommendation for using the DOE settlement payments in conjunction with the Theoretical Reserve moderation proposal creates greater consistency and predictability in year-over-year increases in customer rates. During the Evidentiary Hearing, the Company agreed to true-up and refund to customers any DOE payments received in excess of the amount reflected in the Commission's final Order for the 2015 Step.

Department position: the Department raised concerns about using the DOE settlement funds as a moderation mechanism, but did not oppose using the DOE funding in excess of the current decommissioning accrual at this time and for purposes of this rate case. The Department noted that according to the Company's response in discovery, the DOE payments will be approximately $10 million less than estimated by the Company in its initial filing and recommended a corresponding adjustment. During the Evidentiary Hearing, the Department agreed that the Company had provided support for the reduced DOE payment amount of $25.74 million, and agreed with the Company's $10.1 million adjustment (decrease in DOE refund revenues, so increase in revenue requirements).

OAG position: the OAG recommended that the Commission carefully consider whether the Company's moderation proposal is reasonable and in the public interest. The OAG stated that using DOE refunds to lower rates does not produce any real savings to ratepayers, since the DOE refunds belong to the ratepayers regardless of the type of mechanism that is used to return them.

Commercial Group position: the Commercial Group recommended that the Commission approve the use of excess DOE payments for rate increase moderation, however, funds received in 2013 should be used to moderate the rate increase for the 2014 test year and funds received in 2014 should be used to moderate the rate increase for the 2015 Step.

Adjustment: $10.1 million increase in revenue requirements (Company and Department).

Record Citations:
Sparby Rebuttal, Exh. 26 at 12-13
Clark Direct, Exh. 99 at 28-29
Clark Rebuttal, Exh. 100 at 36-42
Heuer Direct, Exh. 88 at 8, 155
Heuer Rebuttal, Exh. 90 at 28-29
Heuer Opening Statement, Exh. 140 at 7
Evidentiary Hearing Transcript, Vol. 3 at 147, 149-151, 165-166 (Heuer)
Robinson Direct, Exh. 95 at 33-34
Robinson Rebuttal, Exh. 97 at 11-19
Perkett Direct, Exh. 92 at 43
Perkett Opening Statement, Exh. 130 at 1
Evidentiary Hearing Transcript, Vol. 2 at 55 (Perkett)
Campbell Direct, Exh. 429 at 75-94
Campbell Surrebuttal, Exh. 435 at 65-69
Campbell Opening Statement, Exh. 450 at 3-4
Lindell Direct, Exh. 370 at 11-16
Chriss Direct, Exh. 225 at 12

35. MYRP: Refund Mechanism Due to Postponed or Cancelled Capital Projects

Resolved between NSP and the Department. No other party provided testimony on this issue.

NSP position: during the Evidentiary Hearing, the Company proposed a refund mechanism for both 2014 test year and 2015 Step. The Company's understanding is that the Department supports the mechanism, which is based on the difference between the Commission approved revenue requirements and actual revenue requirements associated with capital additions. For the 2014 test year, the mechanism will start with the Commission approved 2014 test year plant related base revenue, but exclude the 2014 plant additions for the Monticello LCM/EPU project or 2015 Step projects (Adjusted Test Year 2014 Plant Related Revenue Requirements). The mechanism would then compare the Adjusted Test Year 2014 Plant Related Revenue Requirements to the actual plant related base rate revenue requirements, again excluding the 2014 plant additions for the Monticello LCM/EPU project or 2015 Step projects (Adjusted Actual 2014 Plant Related Revenue Requirements). If the Adjusted Actual 2014 Plant Related Revenue Requirements is lower than the Adjusted Test Year 2014 Plant Related Revenue Requirements, the Company will include the amount in the interim rate refund and the calculation of final rates in 2015. The Company will submit a compliance filing prior to the implementation of final 2014 rates that

- calculates the Adjusted Actual 2014 Plant Related Revenue Requirements and compares it to the Adjusted Test Year 2014 Plant Related Revenue Requirements,
- compares the 2014 test year to the 2014 actual capital additions, and
- provides an explanation for all project capital additions that were included in actual rate base but not part of the 2014 test year.

A similar refund process will be used for the 2015 Step, however, limited only to the projects included in the 2015 Step.

Department position: the Department recommended that the Company be required to reduce rates for capital projects that do not occur within the 2014 test year or 2015 Step year, and refund to its customers all rates that have been over-collected as a result of the cancellation of projects. Although the first year of MYRP is developed similarly as a traditional rate case, it is tied to MYRP and the standard for ratepayer protection must be increased accordingly. During the Evidentiary Hearing, the Company and Department agreed to a refund mechanism for the 2014 test year and 2015 Step.

Record Citations:
Clark Direct, Exh. 99 at 20-22
Clark Rebuttal, Exh. 100 at 12-14, 19-20
Heuer Opening Statement, Exh. 140 at 3-4
Evidentiary Hearing Transcript, Vol. 3 at 142-143, 152-154 (Heuer)
Perkett Opening Statement, Exh. 130 at 1-2
Evidentiary Hearing Transcript, Vol. 2 at 55, 78-81, 86-88, 93 (Perkett)
Lusti Direct, Exh. 437 at 68-71
Lusti Surrebuttal, Exh. 442 at 47-49

36. MYRP: Compliance for 2015 Step Projects

During the Evidentiary Hearing, the Company proposed the following process in compliance with the Commission's June 17, 2013 Multi-Year Rate Plan Order:

The 2015 Step rates will be set consistent with the Commission's final Order in this proceeding. The Company will provide quarterly compliance reporting during 2015 (April, August, November) to the Commission comparing the most current forecast of each 2015 Step project to the amount included in the 2015 Step. By April 1, 2016, the Company will submit its final compliance report which will include:

- The actual 2015 Step revenue requirement for each project, specifically 2014 actual, 2015 actual and the difference (2015 Step);
- The revenue requirement difference for each 2015 Step project between the 2015 Step actual and 2015 Step test year;
- Explanations for project additions that are greater than included in the 2015 Step;
- In the event the total actual 2015 Step revenue requirement is lower than the total test year 2015 Step revenue requirement, the Company will include in its compliance filing a proposal for rate refund;
- In the event the Company becomes aware of a 2015 Step project cancellation or postponement, the Company will provide 30 day notice including a refund plan.

Record Citations:
Heuer Opening Statement, Exh. 140 at 6-7
Evidentiary Hearing Transcript, Vol. 3 at 145-146 (Heuer)

37. Service Agreement Between NSP and Xcel Energy Services, Inc.

Resolved between NSP and the Department. No other party provided testimony on this issue.

The Company filed on March 24, 2014 a petition to amend the Service Agreement between the Company and Xcel Energy Services, Inc. (Docket No. E,G002/AI-14-234). The Company and the Department agree that any changes that result from the Commission's Order in that Docket should be incorporated into this case.

Record Citations:
Stitt Rebuttal, Exh. 87 at 13-14
Byrne Direct, Exh. 423at 3-5, 48
Byrne Surrebuttal, Exh. 427 at 2-3
Byrne Opening Statement, Exh. 449 at 1
Evidentiary Hearing Transcript, Vol. 5 at 9 (Byrne)
Lusti Direct, Exh. 437 at 21
Lusti Surrebuttal, Exh. 442 at 9

38. Withdrawal of the Hollydale Transmission Project (2014)

Resolved between the Company and the Department. No other party provided testimony on the issue.

The Company noted in discovery that it no longer anticipates the planned capital additions to the Hollydale project and proposed to remove the associated capital costs from the rate base. In Rebuttal, the Company confirmed withdrawal of the Hollydale project and proposed to exclude it from the 2014 test year. The Department supported the Company's recommended adjustment.

Adjustment: $43,000 reduction in revenue requirements and $388,000 reduction in rate base.

Record Citations:
Clark Rebuttal, Exh. 100 at 25-26
Heuer Rebuttal, Exh. 90 at 11-12
Lusti Direct, Exh. 437 at 19-20, 27
Lusti Surrebuttal, Exh. 442 at 7-8

39. Prairie Island EPU/LCM Split Correction (2014)

Resolved between NSP and the Department. No other party provided testimony on this issue.

The Company noted that a transactional assessment of the Prairie Island EPU/LCM project costs to EPU proportion and LCM proportion was completed just prior to filing this rate case. This assessment resulted in additional project costs being assigned to the EPU part of the project. The Company made an adjustment to the interim revenue requirement but did not have time to reflect this change in the test year revenue requirement. In Rebuttal, the Company proposed to remove $2.157 million from the LCM part and add this amount to the EPU part. The Department agreed on the proposed correction.

Adjustment: $158,000 reduction in revenue requirements; $1.418 million reduction in rate base.

Record Citations:
Heuer Rebuttal, Exh. 90 at 8-9, 15
Lusti Direct, Exh. 437 at 18-19, 26-27
Lusti Surrebuttal, Exh. 442 at 2-3

40. Xcel Energy Foundation Administration Cost Correction (2014)

Resolved between NSP and the Department. No other party provided testimony on this issue.

The Company noticed in discovery that it had not removed non-labor related Foundation Administration O&M costs from the test year, and agreed to provide this adjustment in Rebuttal Testimony. In Rebuttal, the Company proposed to remove an additional $114,622 for Foundation Administration costs from the test year. The Department supported this adjustment.

Adjustment: $114,622 reduction in revenue requirements.

Record Citations:
Heuer Direct, Exh. 88 at 10
Byrne Direct, Exh. 423 at 6-7, 48
Byrne Surrebuttal, Exh. 427 at 3-4

Lusti Surrebuttal, Exh. 442 at 31

41. Big Stone Brookings Cost Correction (2014)

The Company noted that subsequent to preparing the capital budget, a forecasted update was made to a component of the Big Stone Brookings transmission project, with an effect of lowering operating costs. The Company made an adjustment to the interim revenue requirement but did not have time to reflect this change in the test year revenue requirement. In Rebuttal, the Company proposed a corresponding adjustment to the test year. In Surrebuttal, the Department agreed on the adjustment.

Adjustment: $145,000 reduction in revenue requirements; $299,000 increase in rate base.

Record Citations:
Heuer Rebuttal, Exh. 90 at 40
Lusti Surrebuttal, Exh. 442 at 12-13

42. Bargaining Unit Wage Increase Correction (2014)

The Company noted that the 2014 test year included a 3.0 percent wage increase for bargaining unit employees. The union ratified a new agreement with a 2.6 percent wage increase after the filing of this rate case. In Rebuttal, the Company proposed a corresponding adjustment to the test year. In Surrebuttal, the Department agreed on the adjustment.

Adjustment: $405,000 reduction in revenue requirements.

Record Citations:
Heuer Rebuttal, Exh. 90 at 41
Lusti Surrebuttal, Exh. 442 at 33

43. Theoretical Reserve for Intangible Plant Correction (2014)

In its initial filing, the Company amortized all of the surplus theoretical reserve for intangible plant accounts over eight years, although the surplus reserve should have been amortized over the average remaining lives of the accounts. In Rebuttal, the Company proposed a corresponding adjustment to the test year. In Surrebuttal, the Department agreed on the adjustment.

Adjustment: $28,000 increase in revenue requirements; $77,000 reduction in rate base.
Record Citations:
Heuer Rebuttal, Exh. 90 at 41-42
Lusti Surrebuttal, Exh. 442 at 13

44. Net Operating Loss Correction (2014)

In its initial filing, the Company's net operating loss calculation in the CCOSS had an error in the calculation of deferred taxes, which were overstated because state tax credits were inadvertently excluded. In Rebuttal, the Company proposed a corresponding adjustment to the test year. In Surrebuttal, the Department agreed on the adjustment.

Adjustment: $366,000 reduction in revenue requirements; $190,000 increase in rate base.

Record Citations:
Heuer Rebuttal, Exh. 90 at 442-43
Lusti Surrebuttal, Exh. 442 at 14

45. Monticello Cyber Security Correction (2014)

At the time of its initial filing, the Company assumed that the Monticello Cyber Security project's in-service date would be delayed to 2015, and made a corresponding adjustment to the interim rate revenue requirement. In Rebuttal, the Company stated that the project is in fact on schedule to go into service during the 2014 test year as originally planned, and no adjustment is necessary to the 2014 test year revenue requirement.

Record Citations:
Heuer Rebuttal, Exh. 90 at 43

46. Alliant Wholesale Billing Revenues (2014)

In Rebuttal, the Company noted that it anticipates receiving a refund from Alliant for transmission expense paid, which will also include $561,616 accounted for in 2014 Other Revenue. The Company proposed to include this revenue in the three-year historical average of Other Revenues in a future rate case.

Record Citations:
Heuer Rebuttal, Exh. 90 at 44

47. Cost of Capital Impact (2014 and 2015 Step)

The Company will incorporate the Commission's final Order regarding capital structure, cost of debt, ROE, and overall ROR and calculate the adjustment to reflect final decisions in this case.

Record Citations:
Heuer Opening Statement, Exh. 140 at 3, 8
Evidentiary Hearing Transcript, Vol. 3 at 142, 147 (Heuer)

48. Net Operating Loss Impact (2014 and 2015 Step)

The Company calculated the impacts of its revised positions on net operating loss calculations, based on the Company's post-hearing position. The Department also calculates the NOL effect resulting from its adopted positions. The Company and the Department agreed that the NOL will need to be recalculated to reflect the impact of final decisions in this case.

Record Citations:

Heuer Rebuttal, Exh. 90 at 45-46
Heuer Opening Statement, Exh. 140 at 3, 8
Evidentiary Hearing Transcript, Vol. 3 at 142, 147 (Heuer)
Lusti Surrebuttal, Exh. 442 at 14

49. Cash Working Capital Impact (2014 and 2015 Step)

The Company calculated the CWC adjustment for 2014 and 2015 based on the Company's post-hearing position. The Department also calculates the CWC adjustment resulting from adoption of its positions. The Company and the Department agreed that CWC will need to be recalculated as part of the final compliance filing based on the revenue requirement approved in this case.

Record Citations:
Heuer Rebuttal, Exh. 90 at 46
Heuer Opening Statement, Exh. 140 at 3, 8
Evidentiary Hearing Transcript, Vol. 3 at 142, 147 (Heuer)
Lusti Direct, Exh. 437 at 24-25
Lusti Surrebuttal, Exh. 442 at 15, 42

49A. Interest Synchronization Methodology and Calculation (2014 and 2015 Step)

The Company and Department agreed on the methodology and that final interest synchronization calculation will occur after the Commission determines all cost of debt, rate base and income statement adjustments in this proceeding. As to the calculation results, for the 2014 test year and the 2015 Step, after all decisions are made, the Company and Department will calculate the 2015 Step Interest Synchronization, and no decision is needed by the ALJ on the result of the calculation.

Record Citations:
Lusti Direct, Exh. 437 at 43-44
Lusti Surrebuttal, Exh. 442 at 34

PART 2 – DEPARTMENT RATE DESIGN ISSUES

A. Disputed Department Issues – Rate Design

50. Decoupling Mechanism

Disputed among NSP, the Department, OAG, ECC, CEI, ICI Group, Commercial Group, and AARP. No other party provided testimony on this issue.
NSP Position: the Company proposed to implement a partial Revenue Decoupling Mechanism (RDM) for its Residential and Commercial Non-Demand customers. The Company accepted three recommendations by the Department: 1) implement RDM as a three-year pilot program; 2) disallow RDM surcharges in the year after the Company fails to achieve energy savings equal to 1.2 percent of retail sales; and 3) include in the annual RDM evaluation plan a comparison of how revenues under traditional regulation would have differed from those collected under partial and full decoupling.

- Partial vs. Full Decoupling: the Company recommended partial decoupling, which removes the effect of weather from monthly deferrals, because it is consistent with the Company's gradual approach to decoupling. Exclusion of weather effects does not affect RDM's main goal of removing the Company's disincentive to promote conservation. The Company believed that the Department and OAG based their conclusions to recommend full decoupling on a particular period of time that had unusual weather patterns. Simulations from other time periods showed that partial decoupling produced refunds to customers in several years. The Company stated it would evaluate at the conclusion of the pilot program whether a change to full decoupling will be appropriate.

- Cap on RDM Surcharges: the Company proposed a soft cap (deferral amounts in excess of the cap are carried over in the deferral account for recovery in subsequent years) of five percent of base revenue, excluding fuel and all applicable riders, as modified in Rebuttal. In case the Commission will order the Company to implement a full decoupling mechanism, the Company proposed a soft cap of 10 percent of base revenue, excluding fuel and all applicable riders. The Company stated that a hard cap would not fully resolve the issue of disincentive to promote energy efficiency, and hard caps are rarely used in electric decoupling mechanisms. In addition, about half of the industry decoupling mechanisms do not use a cap at all and the Company's proposed five percent cap is lower than the typical industry cap level of 10 percent.

- Applicable Customer Groups: the Company believed it would be inappropriate to expand RDM to C&I Demand class, as suggested by the OAG. The Company limited its RDM proposal to Residential and Commercial Non-Demand customers because this is consistent with the gradual approach and because for these classes the energy efficiency disincentive is the largest. Also the implementation of the decoupling mechanism is the most straightforward for these customer classes.

- Calculation of RDM Refunds and Surcharges: the Company recommended that decoupling adjustments be calculated as a dollar per kWh basis. An adjustment as a percentage of the total bill, in absence of IBR, would harm low-use customers.

- Excluding Service Outages from RDM Deferrals: the Company stated that the amount of revenue at stake is so low that that the cost of complicating the RDM design and the uncertainty in estimating lost sales outweigh any benefits of excluding service outages from RDM deferrals, as proposed by AARP.

- Theoretical Concerns: the Company did not believe that the theoretical concerns raised by other Parties were warranted. The Company stated that evaluation results do not show any widespread customer confusion because of RDM and also concerns about cross-subsidies are unwarranted because RDM calculates separate RDM deferrals and rate changes separately for each customer group. The Company expected it to become increasingly difficult to meet its energy efficiency goals due to changing market circumstances, such as stricter efficiency goals and standards and decreasing relative value of efficiency.

Department position: the Department made several recommendations to modify the Company's proposed RDM, and the Company accepted three of them as discussed above.

- Partial vs. Full Decoupling: the Department analyzed the hypothetical results if an RDM had been in place from 2009 to 2013 and from 2004 to 2013. Based on these analyses, the Department concluded that the proposed partial RDM would have an adverse impact on the Company's residential ratepayers and should not be approved. The Department noted that partial decoupling has the potential to significantly increase ratepayer costs and full decoupling could have similar effects, but to a much smaller extent. The Department recommended adopting a full decoupling mechanism as a three-year pilot program. If the Commission will not approve the full decoupling mechanism, the Department recommended maintaining current rate regulation with no RDM.

- Cap on RDM Surcharges: the Department recommended a hard cap of no greater than three percent of total revenue, including fuel and all applicable riders, to help mitigate the adverse impact of the full decoupling mechanism on ratepayers. The Department emphasized that a soft cap is not a real cap since it only changes the timing of the surcharge, but not its dollar amount. Also, the Department did not believe that a hard cap would reduce the Company's interest to maximize energy savings, because the DSM incentive mechanism is so strong.

- Applicable Customer Groups: the Department agreed with the Company's proposal and recommended that the Commission not extend decoupling to additional customer classes at this time.

- Energy Achievement Threshold: the Department recommended that the Company not be allowed to surcharge customers in any year after the Company fails to achieve energy savings equal to 1.2 percent of retail sales.

OAG position: the OAG opposed RDM because it does not provide the Company an incentive nor does it have measureable benefits. The OAG also asserted RDM can cause customer confusion with additional line items on bills and complex deferral structure of surcharges. In addition, the OAG noted that the Company has been able to meet its energy efficiency goals in the past without any decoupling mechanism. Based on an analysis of Company data from 2009 to 2013, the OAG concluded that a full decoupling mechanism would have cost ratepayers far less than a partial decoupling mechanism. The OAG also questioned why RDM was not extended to the C&I Demand class. If the Commission will adopt a decoupling mechanism, the OAG agreed with the recommendations made by the Department, but advised the Commission to consider a lower hard cap at one to two percent. The OAG also recommended that if RDM is adopted, the customer charge should remain at its current level or to be decreased.

ECC position: ECC recommended that if RDM is approved by the Commission, the Company's request to increase customer charge should be rejected and the Company should be required to implement additional conservation programs, including the low-income renter program proposed by ECC. ECC believed that low-use, low-income households will be adversely affected by the Company's RDM and proposed that the decoupling adjustments be calculated as a percentage of the total bill basis rather than the Company-proposed dollar per kWh basis to align with the IBR proposal.

CEI position: CEI supported the Company's RDM proposal and stated that it represents a carefully tailored and wholly appropriate response to guidance from the legislature and the Commission. CEI noted that the Company's proposal is in the mainstream of utility decoupling mechanisms and designed to minimize rate volatility. CEI opposed full decoupling and a hard cap on surcharges. However, if RDM is approved by the Commission, CEI recommended that the Company's request to increase customer charge for the Residential class should be rejected. In order to align the IBR and RDM proposals, CEI also recommended that the decoupling adjustments be calculated as a percentage of the total bill basis rather than the Company-proposed dollar per kWh basis.

ICI Group position: ICI Group recommended that the Company's RDM proposal should be rejected. ICI Group was concerned that RDM would be extended in the future to larger commercial and industrial demand customers. ICI Group also believed that RDM, as proposed by the Company, would recover lost revenues, including costs never incurred by the utility.

Commercial Group position: Commercial Group agreed that if the Commission approves RDM, it should exclude Commercial Demand customers as proposed by the Company.

AARP position: AARP recommended that the Commission reject the Company's RDM proposal. AARP noted that there is little evidence of positive relationship between decoupling and energy efficiency. AARP believed the Company's RDM proposal would unfairly shift risk from the Company to consumers, particularly low-use customers who are less able to benefit from DSM efforts, and RDM would also create cross-subsidies among customer classes. If the Commission will accept RDM, AARP recommended several protections for customers, including Company commitment to provide cost-effective DSM programs, a cap of not more than two percent on annual surcharges, and exclusion of service outages from RDM deferrals. In addition, AARP agreed with the OAG recommendations related to pilot program, hard cap, and full decoupling.

Record Citations:
Sparby Direct, Exh. 25 at 3, 30-31
Sparby Rebuttal, Exh. 26 at 13-14
Hansen Direct, Exh. 109 at 2-20
Hansen Rebuttal, Exh. 110 at 1-23
Hansen Surrebuttal, Exh. 111 at 1-18
Evidentiary Hearing Transcript, Vol. 3 at 94-110 (Hansen)
Sundin Rebuttal, Exh. 42 at 3-6
Evidentiary Hearing Transcript, Vol. 1 at 141, 145-147, 152-161, 165 (Sundin)
Davis Direct, Exh. 417 at 7-14, 17-40
Davis Rebuttal, Exh. 418 at 2-8
Davis Surrebuttal, Exh. 419 at 1-17
Davis Opening Statement, Exh. 447 at 1-2
Evidentiary Hearing Transcript, Vol. 4 at 135-145 (Davis)
Nelson Direct, Exh. 375 at 53-61
Nelson Rebuttal, Exh. 377 at 38-39
Nelson Opening Statement, Exh. 142 at 1
Evidentiary Hearing Transcript, Vol. 3 at 224, 274-276 (Nelson)
Colton Direct, Exh. 234 at 27-35
Cavanagh Direct, Exh. 290 at 1-13
Cavanagh Rebuttal, Exh. 294 at 1-10
Cavanagh Opening Statement, Exh. 300 at 1

Evidentiary Hearing Transcript, Vol. 3 at 60-89 (Cavanagh)
Chernick Direct, Exh. 280 at 29-30
Glahn Direct, Exh. 250 at 12-15
Glahn Surrebuttal, Exh. 251 at 3-4
Chriss Direct, Exh. 225 at 14-15
Brockway Direct, Exh. 310 at 4-23
Brockway Rebuttal, Exh. 311 at 1-22
Brockway Surrebuttal, Exh. 312 at 1-5, 8-9

51. CCOSS

Disputed among NSP, the Department, OAG, MCC, and XLI. CEI also provided testimony related to one part of the CCOSS.

The Company, Department, OAG, MCC and XLI each present separate CCOSSs. The table below summarizes the primary positions taken by each party on disputed CCOSS elements in this case.

CCOSS Sub-Issues

Issue	NSP	Department	OAG	MCC	XLI
Classification of Fixed Production Plant	Plant Stratification	Plant Stratification	Plant Stratification	Straight Fixed-Variable (Peak Demand)	Modified Plant Stratification (Net Depreciated Replacement Value)
Allocation of Economic Development Discounts	Allocate using TY 2014 Present Revenues	Classify 100% energy, allocate based on kWh sales	Classify 100% energy, allocate based on kWh sales	Allocate using TY 2014 Base Revenues	Allocate using TY 2014 Present Revenues
Allocation of Interruptible Rate Discounts	Allocate to all customers	Allocate to all customers			Do not allocate to interruptible customers
Allocation of Other Production O&M	Predominant Nature Method	Location Method, (or overall investment method used in 12-961)	Location Method	Predominant Nature Method	Predominant Nature Method
Nobles and Grand Meadow Wind Generation	Classify 100% capacity (or Percent of Base Revenue)	Plant Stratification, (or classify 100% energy)	Classify 100% energy	Percent of Base Revenue, (or classify 100% capacity)	Classify 100% capacity
Pleasant Valley and Borders Wind	Plant Stratification	Plant Stratification	Plant Stratification	Rider Recovery	
Split to Demand vs. Customer Distribution Costs	Minimum Distribution System (MDS) Method; Minimum Systems Study,		MDS and the Study are flawed, over-estimating customer costs; allocate 10%		

Issue	NSP	Department	OAG	MCC	XLI
	assumptions are sound		less as customer cost		
D10S Capacity Allocator	Calculate based on NSP system peak		NSP system peak that is coincident with MISO peak	Calculate based on NSP system peak	Calculate based on NSP system peak
Plant Stratification Method – Update Cost Data		Assuming that the Company's use of updated information in Rebuttal Testimony is appropriate, use plant-specific data for Pleasant Valley and Borders wind projects and use 2013 cost data for all production plant costs in the application of equivalent peaker method			

The OAG also recommended that the Commission order the Company in its next rate case to thoroughly discuss how PPAs are integrated into the Company's resource planning, to conduct a zero-intercept study, and to update the Minimum Systems Study using current data and clearly document the study methodology. The Company agreed to reexamine all the assumptions supporting its Minimum Systems Study and to conduct a zero-intercept study if all the necessary data can be compiled.

Record Citations:
Peppin Direct, Exh. 102 at 3-30
Peppin Rebuttal, Exh. 103 at 2-41
Peppin Surrebuttal, Exh. 104 at 1-9
Evidentiary Hearing Transcript, Vol. 2 at 149-156 (Peppin)
Foss Direct, Exh. 69 at 1-9
Ouanes Direct, Exh. 408 at 18-44
Ouanes Rebuttal, Exh. 412 1-13
Ouanes Surrebuttal, Exh. 414 at 2-16
Ouanes Opening Statement, Exh. 445 at 1-4
Evidentiary Hearing Transcript, Vol. 4 at 58-128 (Ouanes)
Davis Direct, Exh. 417 at 5-7
Nelson Direct, Exh. 375 at 2-33
Nelson Rebuttal, Exh. 377 at 2-19
Nelson Surrebuttal, Exh. 378 at 2-17
Nelson Opening Statement, Exh. 142 at 1

Evidentiary Hearing Transcript, Vol. 3 at 226-229, 231-265, 277-289 (Nelson)
Maini Direct, Exh. 343 at 14-30
Maini Surrebuttal, Exh. 345 at 10-19
Evidentiary Hearing Transcript, Vol. 4 at 17-18, 23-29 (Maini)
Pollock Direct, Exh. 260 at 33-36
Pollock Rebuttal, Exh. 262 at 2-23
Pollock Surrebuttal, Exh. 263 at 24-29
Pollock Opening Statement, Exh. 264 at 2-3
Evidentiary Hearing Transcript, Vol. 3 at 31-34, 42-43, 45-49, 50-53 (Pollock)

52. Amount of Interruptible Service Discounts and Demand Charges

Disputed among NSP, the Department, MCC and XLI. No other party provided testimony on this issue.

NSP position: the Company proposed to increase the interruptible service discounts by 6 percent for the Performance Factor C service category, with corresponding increases for other Performance Factors that result in an overall increase of 5.1 percent for all service categories. The Company sets the discounts based on market-based approach to attract an optimal supply of interruptible load. The Company believed its proposed interruption discount for the Short Notice option at $5.85/kW per month is appropriate, considering the flexibility to quickly respond to system capacity requirements and incremental value to Short Notice customers. The proposed discounts balance the principles of moderation and longer-term resource planning needs.

Department position: the Department recognized that interruptible customers have seen rates increase in the recent years without a corresponding increase in the interruptible discount. The Department recommended a more moderate 3 percent increase to the Company's interruptible discount rates as measured at the Performance Factor C level. Under the Company's market based approach, the Company sets its interruptible rates at a level the Company believes will attract an optimal supply of interruptible load. The Company stated that it does not expect that increasing the discount rate will result in a material increase in its interruptible load.

MCC position: in order to maintain and expand the interruptible load, MCC recommended that the Tier 1 Performance Factor C credit be increased from the current $60.60/kW per year to $77.24/kW per year. MCC pointed out that interruptible credits and firm demand charges do not have comparable increases and the number of Company customers receiving interruptible service and interruptible load has been decreasing. If the Commission does not approve the MCC proposal, any other accepted recommendation should be grossed up by an additional 6.1 percent to reflect the avoidance of the planning reserve margin requirements.

XLI position: XLI stated that no increase is appropriate for the controllable demand charge for the Short Notice option and recommended the interruption discount for the Short Notice option be increased to at least $6.76/kW per month. XLI noted that the Company is proposing to increase the demand charge for Short Notice option by 19 percent but to increase the interruptible credit for Short Notice option only by 5 percent.

Record Citations:

Huso Direct, Exh. 105 at 26-28
Huso Rebuttal, Exh. 107 at 34-38
Evidentiary Hearing Transcript, Vol. 2 at 166-172, 181-185 (Huso)
Peirce Direct, Exh. 420 at 24-26, SLP-9
Peirce Surrebuttal, Exh. 422 at 14
Evidentiary Hearing Transcript, Vol. 4 at 200-203 (Peirce)
Schedin Direct, Exh. 340 at 23-24
Schedin Surrebuttal, Exh. 342 at 13
Maini Direct, Exh. 343 at 34-41
Maini Surrebuttal, Exh. 345 at 21-26
Maini Opening Statement, Exh. 145 at 1
Evidentiary Hearing Transcript, Vol. 4 at 12 (Maini)
Pollock Direct, Exh. 260 at 48-55
Pollock Surrebuttal, Exh. 263 at 35-38
Pollock Opening Statement, Exh. 264 at 3-4
Evidentiary Hearing Transcript, Vol. 3 at 34 (Pollock)

53. Revenue Apportionment

Disputed among NSP, the Department, OAG, MCC, XLI, and the Commercial Group.

NSP position: the Company proposed to move the Residential class 75 percent closer to cost; set the C&I Non-Demand apportionment at the cost-based level; maintain the current level of Lightning class revenues; and recover the remaining revenue requirement from the C&I-Demand class. The Company proposed an updated revenue apportionment for 2014 and 2015, presented in witness Huso's Rebuttal Testimony, Table 3 and Table 4. In Rebuttal, the Company revised the C&I Non-Demand class to 75 percent movement to cost. The Company and the Department agreed on the proportional adjustment mechanism to adjust the revenue apportionment to reflect the Commission's final Order in this case.

Department position: the Department's proposed, updated revenue apportionment for 2014 and 2015 was presented in witness Peirce's Surrebuttal Testimony, Table 3 and Table 4. The proposal moved all classes closer to cost while moderating the overall rate increases to all classes. The Department relied on the CCOSS recommendations of witness Dr. Ouanes to develop its initial apportionment of revenue responsibility. The Department updated its apportionment by proportionally adjusting the revised revenue requirement to reflect its apportionment recommendations in Direct Testimony. The proportional adjustment methodology is consistent with the methodology approved by the Commission in the Company's prior to rate cases.

OAG position: the OAG stated that CCOSS is an imprecise model with no measurement for error, and therefore it should not be used as an absolute metric for rates, and also non-cost factors should be considered in rate design. The OAG's proposed revenue apportionment for 2014 and 2015 was presented in witness Nelson's Direct Testimony, Table 9 and Table 10.

MCC position: MCC recommended that the revenue allocation follow the cost of service. MCC opposed the revenue apportionment recommendations made by the Department and the OAG. MCC did not oppose using the Company's CCOSS to establish the revenue apportionment, so long as the CCOSS was modified to include percent of base revenue approach for the classification of Nobles and Grand Meadow Wind generation.

XLI position: XLI believed that CCOSS should be the primary factor in determining revenue apportionment and it is important to set rates to class cost in order to promote equity, efficiency, conservation, and stability. XLI also noted that the subsidy provided by C&I Demand customers should be eliminated. XLI made revenue apportionment recommendations based on the Company's CCOSS (as modified by XLI) and presented them in witness Pollock's Direct Testimony, Schedule 10.

Commercial Group position: the Commercial Group did not oppose the Company's proposed revenue allocation, based on the Company's proposed CCOSS. The Commission should, at the minimum, maintain the Company's proposed movement towards cost of service, and additionally determine to what extent rates can be moved closer to cost of service for each class.

Record Citations:
Huso Direct, Exh. 105 at 7-13
Huso Rebuttal, Exh. 107 at 1-9
Peirce Direct, Exh. 420 at 5-10
Peirce Surrebuttal, Exh. 422 at 1-4
Peirce Opening Statement, Exh. 448 at 1
Evidentiary Hearing Transcript, Vol. 4 at 148-150 (Peirce)
Nelson Direct, Exh. 375 at 33-40
Nelson Rebuttal, Exh. 377 at 21
Nelson Surrebuttal, Exh. 378 at 17-18
Maini Direct, Exh. 343 at 30-34
Maini Surrebuttal, Exh. 345 at 19-21
Pollock Direct, Exh. 260 at 37-47
Pollock Rebuttal, Exh. 262 at 24-29
Pollock Surrebuttal, Exh. 263 at 30-32
Pollock Opening Statement, Exh. 264 at 3
Evidentiary Hearing Transcript, Vol. 3 at 34 (Pollock)
Chriss Direct, Exh. 225 at 4-5, 13-14

54. Residential and Small General Service Customer Charges

Disputed among NSP, the Department, OAG, ECC, CEI, and AARP. No other party provided testimony on this issue.

NSP position: the Company proposed a $1.25 increase in customer charges for each Residential service category and a $1.50 increase for the Small General Service customers, as presented in Table 8 in witness Huso's Direct Testimony. The Company believed its proposed customer charges appropriately balance several factors, including the cost of service, moderation, intra-class equity, and conservation. The Company believed its recommendation is also consistent with the Commission's most recent decisions regarding customer charges.

Department position: because the Company recently raised customer charges, and to reflect the customer charges set in recent other electric utility rate cases, the Department recommended a more modest increase of $.50 for each Residential service category and for the Small General Service customers. The Department stated that low income customers exist across all usage levels, and a balanced approach to rate design is therefore necessary and reasonable.

OAG position: the OAG opposed any increases in customer charges for several reasons: multiple recent increases in the customer charge, relatively high percentage increase proposed, disproportionate impact on low-use residential customers, and effect as disincentive to conserve energy. The OAG also recommended that if the Commission orders a decoupling mechanism, then the customer charges should remain at the current level or be decreased.

ECC position: ECC believed that the increased customer charge proposed by the Company will have substantial adverse effects on low-income customers and their ability to participate in energy efficiency programs, and therefore it should be rejected. ECC also believed that the Company's data and calculations have methodological and data errors and the Company's discussion on the impact of customer charges on LIHEAP customers is unreliable. In addition, ECC stated that the concern that a lower customer charge will harm low-income, high-use customers is unwarranted.

CEI position: CEI recommended that the residential customer charges should not be increased. CEI believed that the Department used the Company's overstated customer costs as a basis to determine appropriate customer charges and the Department's concern about intra-class subsidiaries is unwarranted. Decoupling is another reason not to increase customer charges.

AARP position: AARP recommended that the residential customer charges should remain at their current levels. The increased customer charges proposed by the Company will place undue burdens on low-use residential customers and reduce the incentive to conserve energy for higher-use customers. The extraordinary situation of some extremely high-use residential customers should not determine customer charge policy for the vast majority of residential customers.

Record Citations:
Huso Direct, Exh. 105 at 14-20
Huso Rebuttal, Exh. 107 at 24-33
Huso Surrebuttal, Exh. 108 at 7-9
Peirce Direct, Exh. 420 at 12-13
Peirce Surrebuttal, Exh. 422 at 6-12
Peirce Opening Statement, Exh. 448 at 1
Evidentiary Hearing Transcript, Vol. 4 at 148, 150-165, 183-196, 204-220 (Peirce)
Nelson Direct, Exh. 375 at 40-52, 59
Nelson Rebuttal, Exh. 377 at 22-23
Nelson Surrebuttal, Exh. 378 at 21-23
Colton Direct, Exh. 234 at 29, 35-41
Colton Rebuttal, Exh. 237 at 1-14
Colton Opening Statement, Exh. 242 at 1-2
Evidentiary Hearing Transcript, Vol. 3 at 12-15 (Colton)
Marshall Rebuttal, Exh. 238 at 1-6
Chernick Direct, Exh. 280 at 3, 26-29

Chernick Rebuttal, Exh. 293 at 1-16
Chernick Opening Statement, Exh. 299 at 1
Evidentiary Hearing Transcript, Vol. 3 at 54-55 (Chernick)
Cavanagh Direct, Exh. 290 at 8-9
Cavanagh Opening Statement, Exh. 300 at 1
Evidentiary Hearing Transcript, Vol. 3 at 76 (Cavanagh)
Brockway Direct, Exh. 310 at 24-33
Brockway Surrebuttal, Exh. 312 at 10-11

55. Low-Income Discount Program

Resolved among NSP, the Department, and ECC. No other party provided testimony on this issue.

NSP position: the Company disagreed with the Department's recommendation to expand the low-income discount program's eligibility, because it would require an alternative administrative process with Company validation of eligibility, because of compliance concerns with the current statutory framework for the low-income discount program, and because there is sufficient federal funding available for all LIHEAP eligible customers.

Department position: in light of the IBR Stipulation, the Department no longer supports its original position and is in agreement with NSP and ECC regarding expansion of the low-income discount program.

ECC position: ECC disagreed with the Department recommendation because the Minnesota law governing the low-income discount rider requires that participants receive LIHEAP and because the program administration would be expensive and burdensome.

Record Citations:
Gersack Surrebuttal, Exh. 74 at 10-12
Grant Rebuttal, Exh. 416 at 6
Marshall Surrebuttal, Exh. 240 at 8-9

B. Resolved Department Issues – Rate Design

56. CCR – Amount of Economic Development Discounts

Resolved among NSP, the Department, and OAG. No other party provided testimony on this issue.

The Department recommended that the 2014 and 2015 Competitive Response Rider (CRR) economic development discounts to be recovered in base rates should be reduced (halved) to the level of actual 2013 economic development discounts. In Rebuttal, the Company agreed on this proposal for this case. Also the OAG supported the Department's recommendation.

Record Citations:
Huso Rebuttal, Exh. 107 at 38-39
Ouanes Direct, Exh. 408 at 41-44
Ouanes Surrebuttal, Exh. 414 at 11-12

Nelson Rebuttal, Exh. 377 at 19

57. FCA Rider/Base Cost of Energy – Nuclear Disposal Fees (2014)

Resolved between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company explained that the spent nuclear fuel disposal fee is included in the 2014 test year as a component of the cost of fuel as well as fuel revenue (making it cost neutral), therefore the test year revenue deficiency is not materially affected by the removal of the disposal fee from the test year. The Company recommended that the base cost of energy be adjusted to reflect the removal of the disposal fee in compliance at the conclusion of this case.

Department position: the Department noted that the Company collects the DOE spent nuclear disposal fees through the FCA, and the Company received notification from the DOE that the disposal fee was reduced to zero effective May 16, 2014. The Department recommended that the base cost of energy amount ($0.02780 per kWh) and the class-specific base costs of energy amounts be reduced accordingly. The Department-recommended base cost of energy was $0.02748 per kWh.

Record Citations:
Heuer Rebuttal, Exh. 90 at 13-14
Ouanes Direct, Exh. 408 at 14-18

58. CIP Rider: CCRC and CAF

Resolved between NSP and the Department. No other party provided testimony on this issue.

The Company proposed to zero out and remove Conservation Cost Recovery Charge (CCRC) from base rates and recover all CIP program costs through the CIP Adjustment Factor (CAF). The Department supported the Company's proposal. The Company agreed that the CCRC be zeroed out when final rates are implemented. Also, the Company agreed to submit an updated Conservation Cost Recovery Adjustment (CCRA) filing 90 days before final rates are estimated to go into effect.

Record Citations:
Heuer Rebuttal, Exh. 90 at 10-11
Peppin Direct, Exh. 102 at 32-33
Peppin Rebuttal, Exh. 103 at 42
Evidentiary Hearing Transcript, Vol. 2 at 157-159 (Peppin)
Davis Direct, Exh. 417 at 3-7
Lusti Surrebuttal, Exh. 442 at 34

59. Windsource Rider

Resolved between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company accepted the Department's recommendation to identify and justify changes to historical data in future Windsource and FCA filings and to use consistent terminology in these filings.

Department position: the Department was concerned that the Company has changed historical data in the Windsource tracker reports without providing any justification, explanation, or even simply identifying such changes. The Department recommended that the Commission require the Company not to change historical data without identifying such changes and providing a justification for such changes in Windsource and FCA filings. The Department also had concerns about using confusing terminology in the Windsource and FCA reports and recommended that the Company should clarify in each FCA and Windsource filing what costs are included in the Windsource Contract Payments.

Record Citations:
Peppin Direct, Exh. 102 at 31-32
Peppin Rebuttal, Exh. 103 at 42-43
Ouanes Direct, Exh. 408 at 6-13

60. Time-of-Day Energy Charges/Energy Charge Credit

Resolved between NSP and the Department. No other party provided testimony on this issue.

The Department recommended the Commission approve the Company's proposed TOD Energy Charge methodology and the proposed increase in the energy charge credit.

Record Citations:
Huso Direct, Exh. 105 at 21-25
Peirce Direct, Exh. 420 at 22-24

61. Firm Service Demand Charges

Resolved. No party other than the Company provided testimony on this issue.

The Company proposed to increase firm service demand charges.

Record Citations:
Huso Direct, Exh. 105 at 25-26.

62. Voltage Discount

Resolved. No party other than the Company provided testimony on this issue.

The Company proposed to increase the demand charge discounts for the Transmission voltage level.

Record Citations:
Huso Direct, Exh. 105 at 28.

62A. Base Energy Charges for the C&I Demand Class

Resolved between NSP and the Department. No other party provided testimony on this issue.

The Department accepted the rates proposed by the Company, as they appear consistent with the results of the modified CCOSS recommended by the Department; the Department also recommended approval of the Company's proposed energy rates.

Record Citations:
Peirce Direct, Exh. 420 at 22

PART 3 – OTHER OAG ISSUES

63. CWIP/AFUDC

Disputed among NSP, OAG, and Commercial Group. No other party provided testimony on this issue.

NSP position: the Company disagreed with the recommendations offered by the OAG and Commercial Group and continued to request accounting for CWIP and AFUDC according to long-standing Commission practice. The Company noted that neither FERC nor Minnesota rules allow accumulation of AFDUC when projects are placed in CWIP without an AFUDC offset, and when everything is held constant, FERC and Minnesota methods produce the same results. The AFUDC offset assures that the asset being constructed accumulates the true cost of financing during construction, not the current rate of return. Without AFUDC, shareholders would be providing construction financing through very substantial amounts of invested and reinvested equity at no cost. Internally generated funds should receive a return as internally generated funds are available for distribution for to shareholders. The Company has calculated and applied the AFUDC rate consistent with FERC accounting requirements and also correctly accounted for AFUDC on cancelled or suspended projects. The Company stated that if CWIP and AFUDC were removed from ratemaking for projects that are less than $25 million, the Company would be denied recovery of any cost of capital associated with financing approximately $441 million in CWIP investment in the test year (approximately 60 percent of all CWIP investment).

OAG position: the OAG believed that the Company's accounting for CWIP and AFUDC violates FERC requirements, specifically, because FERC limits CWIP to 50 percent in rate base, allows either CWIP in rate base or AFUDC but not both, and disallows AFUDC during project interruptions. The OAG also noted that the purpose of AFUDC is to recognize the need for external funding, yet the Company accrues AFUDC on virtually all CWIP projects despite the fact that it has substantial internal funding available and all projects do not require external financing. The OAG also believed that the Company has continued to accrue AFUDC during project interruptions and delays. The OAG recommended 1) excluding all CWIP from rate base and removing AFUDC from the income statement, 2) allowing AFUDC only on CWIP projects that cost over $25 million, 3) disallowing AFUDC on CWIP projects that are delayed or interrupted during the period of interruption, and 4) removing equity from AFUDC rate calculation and setting the AFUDC rate at 2.62 percent, which reflects a weighted cost of short-term and long-term debt.

Commercial Group position: the Commercial Group recommended removing CWIP from rate base, because the inclusion of CWIP charges ratepayers for assets during construction that are not yet used and useful. The Commercial Group also noted that CWIP shifts to ratepayers risks that are traditionally assumed by utility investors, and if a project is delayed or not completed, ratepayers have no resource for recovering what they have paid for CWIP in rates.

Disputed amount: $3.8 million reduction in revenue requirements for the 2014 test year and $0.9 million increase in revenue requirements for the 2015 Step (OAG Recommendation).

Record Citations:
Perkett Direct, Exh. 92 at 51-63
Perkett Rebuttal, Exh. 94 at 14-38
Perkett Opening Statement, Exh. 130 at 2-3
Evidentiary Hearing Transcript, Vol. 2 at 58 (Perkett)
Tyson Rebuttal, Exh. 31 at 11-15
Guest Direct, Exh. 91 at 2-11
Lindell Direct, Exh. 370 at 16-29
Lindell Surrebuttal, Exh. 373 at 1-17
Evidentiary Hearing Transcript, Vol. 3 at 196-216, 221-222 (Lindell)
Chriss Direct, Exh. 225 at 10-11

64. Nuclear Refueling Outage Costs – Accounting Methodology

Disputed between NSP and OAG. No other party provided testimony on this issue.

NSP position: the Company proposed to continue to use the deferral and amortization methodology that it has used since 2008, because the methodology moderates the rate increase and variation effects and matches the outage costs to the period when benefits are provided. The Company also requested a carrying charge equal to the rate of return for the unamortized amount of nuclear refueling outage costs. The Company stated that this is a standard ratemaking practice and consistent with past rate cases; the carrying charge simply represents the time value of money until the full amount of expense is recovered, typically over 18 to 24 months.

OAG position: the OAG believed that earning a return on a normal expense is inappropriate and provides an incentive for the Company to increase the scope of nuclear refueling outage costs. The OAG continued to believe that the normalization method to set rates is superior, but recommended that the Company could be allowed to use the deferral and amortization methodology to set rates. However, the OAG suggested that the Company not be allowed to earn any return on nuclear refueling outage costs.

Disputed amount: $4.6 million adjustment and reduction in revenue requirements.

Record Citations:
Robinson Direct, Exh. 95 at 21
Robinson Rebuttal, Exh. 97 at 21-25
Robinson Opening Statement, Exh. 132 at 2
Evidentiary Hearing Transcript, Vol. 2 at 97, 101-105 (Robinson)
Lindell Direct, Exh. 370 at 44-47
Lindell Surrebuttal, Exh. 373 at 24

65. Corporate Aviation Costs (2014)

Disputed between NSP and OAG. No other party provided testimony on this issue.

NSP position: the Company requested recovery of 50 percent of its test year aviation costs ($954,425), accordingly to the Commission's established practice. The Company believed that this adjustment already takes into account many of the concerns raised by the OAG, and any further adjustments are unnecessary. The Company noted that its corporate aviation services provide several generally recognized benefits, and disallowance based on a "vague business reason" analysis of the Company's flight logs is inappropriate.

OAG position: the OAG raised three main concerns regarding the Company's corporate aviation costs: the Company's cost per flight was excessive; many of the flights scheduled did not provide ratepayer benefits; and most of the flights recorded did not include a sufficient business purpose to determine whether the flight was necessary and prudent to provide utility service. Based on these reasons and a review of the Company's flight logs, the OAG recommended disallowing the majority of the corporate aviation costs and allowing recovery of $34,143.

Disputed amount: $920,282 adjustment and reduction in revenue requirements.

Record Citations:
O'Hara Direct, Exh. 75 at 28-32
O'Hara Rebuttal, Exh. 77 at 1-12
O'Hara Opening Statement, Exh. 124 at 1-2
Evidentiary Hearing Transcript, Vol. 1 at 250-251, 253-257 (O'Hara)
Lindell Direct, Exh. 370 at 47-58

66. Interest Rate on Interim Rate Refund

Disputed between NSP and OAG. No other party provided testimony on this issue.
NSP position: the Company disagreed with the OAG recommendation and stated that the interest rate on interim rate refund should not be increased above the Prime Rate. The Company explained that the revenues from the interim rates are considered equivalent to short-term debt for the Company, and the Company's short term borrowing rate is lower than the Prime Rate (0.62 percent vs. 3.25 percent). This means that applying the Prime Rate to refund amounts is a net added cost to the Company because it is higher than the rate Company would pay on other short-term financing. In addition, the refund amount includes any excess expenses (plus any excess return on the rate base determined at the Company's overall rate of return), which means that the OAG recommendation would pay overall rate of return on expenses despite the fact that the Company does not earn a return on expenses.

OAG position: the OAG pointed out that in the Company's last rate case, the Commission determined that the Prime Rate applied to interim rate refunds was inequitable for ratepayers and instead the Company's full weighted cost of capital (i.e., the Company's overall rate of return) should be used as the interest rate for refunds. The OAG recommended that the Company's full weighted cost of capital should be used as the interest rate on interim rate refund also in this case.

Record Citations:
Clark Direct, Exh. 99 at 26
Heuer Rebuttal, Exh. 90 at 37-39
Tyson Rebuttal, Exh. 31 at 23-24
Lindell Direct, Exh. 370 at 58-59
Evidentiary Hearing Transcript, Vol. 3 at 217-221 (Lindell)
Evidentiary Hearing Transcript, Vol. 5 at 78-82, 87-89 (Lusti)

PART 4 – OTHER MCC ISSUES

67. Fuel Cost Recovery Reform

Disputed among NSP, MCC, and XLI. Also the Department provided testimony on this issue.

NSP position: the Company noted that concerns regarding the current process for fuel cost recovery have been raised by other stakeholders in the AAA Docket (Docket No. E999/AA-12-757). Since these issues are not unique to the Company, it believed that the AAA Docket is the best forum to continue the discussions to ensure that all interested Parties have a chance to participate. The Company also believed that it is important to work toward an incentive-based plan that is reasonably within the Company's control.

Department position: the Department acknowledged that designing incentive mechanisms for fuel costs is important and should be done in the near future. Because the issue involves also other investor-owned utilities, the Department believed it would be best addressed in the AAA Docket.

MCC position: MCC stated that the Company's current FCA Rider allows recovery of fuel costs as they occur and shifts burden of proof to consumers to prove after the fact that any costs were imprudent. MCC also noted that although fuel cost recovery has been discussed in the AAA Docket, no action has been taken so far. MCC supported extensive reform of fuel cost recovery, and at a minimum, believed that automatic recovery of replacement fuel costs due to planned or forced outages should not be allowed. MCC recommended that if there is no resolution on this issue in the AAA Docket by the time the Company submits its next rate case, the Company should be ordered to provide a new FCA structure.

XLI position: XLI noted that the annual review of the prudency of the costs recovered through the FCA Rider does not protect customers' interests and places little or no risk of disallowance to the Company. XLI recommended that NSP should be ordered to develop a FCA Rider that places stronger incentives for ensuring that the costs flowing through are prudent and reasonable. Since the discussions in the AAA Docket have not produced results, XLI recommended that the new FCA design should be presented in the Company's next rate case or within 90 days of the Commission's final order in this case, whichever is earlier.

Record Citations:
Clark Rebuttal, Exh. 100 at 42-43
Evidentiary Hearing Transcript, Vol. 2 at 124-127, 134-135 (Clark)
Robinson Rebuttal, Exh. 97 at 25
Ouanes Rebuttal, Exh. 412 at 11-15

Maini Direct, Exh. 343 at 41-43
Maini Surrebuttal, Exh. 345 at 26-27
Pollock Direct, Exh. 260 at 25-32
Pollock Surrebuttal, Exh. 263 at 33-34
Pollock Opening Statement, Exh. 264 at 2
Evidentiary Hearing Transcript, Vol. 3 at 30-31, 49-50, 52 (Pollock)

68. Sherco Unit 3 Outage – Replacement Fuel Costs

Disputed between NSP and MCC. Also the Department provided testimony on this issue.

NSP position: the Company believed that the replacement fuel costs during the Sherco 3 outage would be best addressed in the AAA Docket, because the issue pertains to fuel cost recovery and because these costs were not included in this rate case. In addition, the Company disagreed on capitalizing these costs, because the cost of replacement power should be covered by those customers who used the power during the outage rather than future customers.

Department position: the Department agreed with the Company that the issue of Sherco 3 replacement power costs should be addressed in the AAA Docket.

MCC position: MCC believed that the replacement fuel costs during Sherco 3 outage should be addressed in this case and capitalized over the remaining life of the facility; a corresponding adjustment could be made in the annual FCA filing. Extraordinary replacement energy costs should be paid by ratepayers who benefit from the project over its life.

Record Citations:
Clark Rebuttal, Exh. 100 at 44
Robinson Rebuttal, Exh. 97 at 25
Perkett Rebuttal, Exh. 94 at 47, 54-55
Anderson Rebuttal, Exh. 37 at 4
Lusti Direct, Exh. 437 at 67-68
Schedin Direct, Exh. 340 at 13-15
Schedin Surrebuttal, Exh. 342 at 9
Evidentiary Hearing Transcript, Vol. 3 at 172 (Schedin)

69. Transmission Business Area – Cost Controls

Disputed between NSP and MCC. No other party provided testimony on this issue.

NSP position: the Company disagreed with MCC recommendations and stated that the Transmission organization already has rigorous cost control mechanisms in place. In addition, the Company's use of a +/- 30-percent cost estimate at the certificate of need stage is appropriate for transmission projects, given the level of uncertainty at this stage of the permitting process when the final route for a transmission line has not been determined. For the same reason, a firm cost cap for transmission projects at the certificate of need level would be unreasonable and inappropriate. The Company believed that the MCC recommendation for additional cost controls at the MISO level is inconsistent with recently approved MISO tariff language as well as the FERC's determination that the MISO cost review process is just and reasonable.

MCC position: MCC raised concerns about the Transmission Business Area costs and perceived lack of cost controls. MCC recommended that the Company should create a KPI mechanism to address accountability, directly in the responsibility area of the Vice President of Transmission, for example, including a requirement that each transmission project requiring a certificate of need should have a firm cost cap, which cannot be exceeded for ratemaking purposes without Commission approval.

Record Citations:
Kline Rebuttal, Exh. 67 at 2-37
Schedin Direct, Exh. 340 at 15-21
Schedin Surrebuttal, Exh. 342 at 9-11

70. FERC Cost Comparison Study – KPI Benchmarks

Disputed between NSP, the Department, and MCC. No other party provided testimony on this issue.

NSP position: the Company disagreed with the MCC recommendation and stated that it already has implemented appropriate and sufficient KPIs to manage non-fuel O&M growth. The target for 2014 is to limit recoverable O&M growth to no more than 2.2 percent. In addition, the Company noted that the 2013 Electric FERC Comparison Study is a simplistic analysis, and does not control for the comparability of data, different tracking and reporting systems, relative size of the utility's transmission system, or other similar variations among utilities. Therefore, the Company believed it is inappropriate to use non-fuel and transmission O&M benchmarks from the Comparison Study as KPIs.

Department position: the Department agreed with MCC's recommendation to use benchmarks from the Comparison Study to improve the efficiency of the Company's operations.

MCC position: based on the Company's 2013 Electric FERC Comparison Study, MCC noted that the Company is trending below its peer companies with respect to non-fuel O&M and transmission O&M costs. MCC recommended that the Company should use non-fuel and transmission O&M cost benchmarks from the Comparison Study as KPIs (for those benchmarks that are not in the first or second quartile in the Study) to help improve the efficiency of operations.

Record Citations:
Clark Rebuttal, Exh. 100 at 44-47
Kline Rebuttal, Exh. 67 at 37-45
Ouanes Rebuttal, Exh. 412 at 16
Maini Direct, Exh. 343 at 43-45
Maini Surrebuttal, Exh. 345 at 27-28

71. Coincident Peak Billing

Disputed between NSP and MCC. No other party provided testimony on this issue.

NSP position: the Company disagreed with the MCC's proposal because it would require additional billing processes, would only impact nine customers, and is not consistent with established rate design.

MCC position: MCC recommended that the Company should be required to adopt a coincident peak billing option for customers with demands of 500 kW or more and aggregate all demand interval readings to determine and bill the diversified peak demand.

Record Citations:
Huso Rebuttal, Exh. 107 at 42-44
Evidentiary Hearing Transcript, Vol. 2 at 186-189 (Huso)
Schedin Direct, Exh. 340 at 24-26
Schedin Surrebuttal, Exh. 342 at 13-15
Evidentiary Hearing Transcript, Vol. 3 at 172-175, 187 (Schedin)

72. Definition of Contiguous in Rate Book

Disputed between NSP and MCC. No other party provided testimony on this issue.

NSP position: the Company noted the statutory definition of contiguous property is applicable for only meter aggregations used with net metering, as described in Minn. Stat. 216B.164. No definition is necessary for coincident peak billing, and the Company has provided a definition for other applications as part of discovery.

MCC position: MCC proposed the Company should adopt the new definition of contiguous property, as defined in the new solar law.

Record Citations:
Huso Rebuttal, Exh. 107 at 42-44
Schedin Direct, Exh. 340 at 24
Schedin Surrebuttal, Exh. 342 at 14-15
Exh. 136 (Company Response to MCC-251)

73. Standby Service Tariff – Manner of Service

Resolved between NSP and MCC. No other party provided testimony on this issue.

NSP position: the Company agreed that MCC's recommendations related to standby service tariff should be reviewed in the separate Docket No. E002/M-13-315. The Company did indicate it disagreed with the positions offered by MCC.

MCC position: MCC requested that its testimony regarding standby rates be included in Docket No. E002/M-13-315. MCC recommended that the Company is required to provide true firm standby service by reserving a block of standby capacity from its own resources to serve all of its standby customers as a group, or otherwise the Company should bear the responsibility for certifying the customers' generators with MISO.

Record Citations:
Huso Rebuttal, Exh. 107 at 40-42
Schedin Direct, Exh. 340 at 26-30
Schedin Surrebuttal, Exh. 342 at 15-16

74. DG Tariff Change

Resolved between NSP and MCC. No other party provided testimony on this issue.

NSP position: the Company noted that it was under the impression that it had agreed with MCC to work through the advisory group Rulemaking to incorporate the DG tariff change. The Company agreed to file the DG tariff change as a miscellaneous filing in July 2014.

MCC position: MCC stated that under the 2010 rate case Stipulation and Settlement Agreement, NSP was required to submit a DG tariff change which would place a cap on DG interconnection study fees. In October 2013, NSP and MCC agreed on the terms of the DG tariff change, but the Company has not yet filed the change. In Surrebuttal, MCC acknowledged that the Company was going to make a miscellaneous tariff filing to address the DG Tariff.

Record Citations:
Huso Rebuttal, Exh. 107 at 40
Schedin Direct, Exh. 340 at 22-23
Schedin Surrebuttal, Exh. 342 at 12-13

PART 5 – OTHER XLI ISSUES

75. Nuclear Theoretical Depreciation Reserve (2014)

Disputed among NSP, the Department, OAG, and XLI. No other party provided testimony on this issue.

NSP position: the Company opposed the XLI recommendation and stated that the Company's methodology for calculating the nuclear theoretical depreciation reserve is accurate, reasonable, and very similar to theoretical reserve computations by vintage, because it computes a reserve ratio for each account group. The Company also noted that every dollar of accumulated depreciation that is used to lower the revenue requirement over the next five years will need to be paid back over the remaining life, and XLI's proposal would increase revenue requirements in year six by $47.2 million. The Company offered as an alternative to employ regulatory accounting to depreciate the nuclear units over a remaining life that is longer than the license life, extending the useful life 5-10 years beyond the operating license period.

Department position: the Department did not agree with XLI's recommendation because the Department did not support the use of supposed surplus theoretical depreciation reserves to provide a short-term reduction in rates, in part because ratepayers would have to repay this depreciation expense and pay a return on higher rate base as well. In addition, the Department noted that theoretically depreciation reserve give back is not consistent with past depreciation decisions and IRP decisions. Finally, the Department noted that there is no reasonable basis to conclude that ratepayers have overpaid for nuclear depreciation or that there is a "surplus" theoretical reserve.

OAG position: the OAG opposed the XLI recommendation because it is unreasonable and fails to properly analyze the impact on ratepayers in the future.

XLI position: XLI believed the Company's analysis is flawed and severely understates the magnitude of the depreciation reserve surplus that it has accumulated in the nuclear production plant account. The Company's analysis has two main problems: future interim plant additions were included in determining remaining life values, and theoretical reserve amounts were calculated by account total, not by individual asset vintages. XLI stated that the updated amount of accumulated surplus is approximately $208 million (Minnesota Jurisdiction), which is $136 million more than the Company originally estimated. XLI recommended that the Company be required to amortize the nuclear depreciation reserve surplus of $208 million over five years.

Disputed amount: $25.7 million reduction in revenue requirements assuming a five-year amortization.

Record Citations:
Clark Rebuttal, Exh. 100 at 38-39
Perkett Direct, Exh. 92 at 43-51
Perkett Rebuttal, Exh. 94 at 7-14, 55
Perkett Opening Statement, Exh. 130 at 2
Evidentiary Hearing Transcript, Vol. 2 at 57, 66-71, 76-77 (Perkett)
Campbell Rebuttal, Exh. 434 at 2-4, 7
Campbell Opening Statement, Exh. 450 at 11
Lindell Opening Statement, Exh. 141 at 1
Evidentiary Hearing Transcript, Vol. 3 at 190-192 (Lindell)
Pollock Direct, Exh. 260 at 9-19
Pollock Surrebuttal, Exh. 263 at 8-19
Pollock Opening Statement, Exh. 264 at 1-2
Evidentiary Hearing Transcript, Vol. 3 at 28-29, 44-45 (Pollock)
Colton Opening Statement, Exh. 242 at 1-3

76. Black Dog – Unit 2 and 5 Outage Costs (2014)

Disputed between NSP and XLI. No other party provided testimony on this issue.

NSP position: the Company agreed that the FCA proceeding is the appropriate place to address XLI's concerns over the replacement power costs for Black Dog Unit 2 and 5 outages. However, XLI is also seeking disallowance of costs that were incurred outside the 2014 test year and not included in this rate case. The Company stated it would be inconsistent with the principle of test year to disallow these costs. Despite the Company's best efforts, it is not possible to completely eliminate human errors, and the Company believed a human error should not be an automatic reason to disallow costs.

XLI position: XLI noted that the Black Dog Unit 2 outage (also affecting Unit 5) that occurred from December 2012 to March 2013 was the result of a human error. Therefore, XLI recommended that all capital investment and any operating expenses associated with the repair of the unit should be disallowed. Also, XLI suggested that the replacement fuel costs associated with this outage should be disallowed in the next annual FCA proceeding.

Disputed amount: $ 1.838 million reduction in revenue requirements and $24,104 reduction in rate base.

Record Citations:
Clark Direct, Exh. 99 at 44
Heuer Rebuttal, Exh. 90 at 35
Mills Direct, Exh. 58 at 54
Mills Rebuttal, Exh. 60 at 15-19
Evidentiary Hearing Transcript, Vol. 2 at 14-16 (Mills)
Pollock Direct, Exh. 260 at 23-24
Pollock Opening Statement, Exh. 264 at 2
Evidentiary Hearing Transcript, Vol. 3 at 230, 40-41 (Pollock)

77. Renewable Energy Purchase Tariff (Renew-a-Source)

Disputed between NSP and XLI. No other party provided testimony on this issue.

NSP position: the Company confirmed its commitment to begin discussions with XLI and other interested stakeholders on developing a program that addresses XLI interests, however, the Company recommended against a particular deadline for commencing discussions or making a specific tariff proposal.

XLI position: XLI recommended that in order to match around-the-clock high load customers with renewable energy resources, the Company should develop a specific tariff under which the Company can purchase and sell renewable energy directly to qualifying high load factor customers. The Company would have the leverage of negotiating better prices and matching the output of defined portfolio of renewable resources with the customers' load shapes. XLI recommended that the Commission order the Company to work with interested Parties and develop such a new tariff, to be filed no later than the Company's next rate case. XLI also proposed guidelines for the tariff and recommended that discussions on the tariff should commence within 60 days after the final Order is issued in this case.

Record Citations:
Clark Rebuttal, Exh. 100 at 47-48
Evidentiary Hearing Transcript, Vol. 2 at 131-135 (Clark)
Pollock Direct, Exh. 260 at 59-62
Pollock Surrebuttal, Exh. 263 at 42-43
Pollock Opening Statement, Exh. 264 at 4-6
Evidentiary Hearing Transcript, Vol. 3 at 35-37 (Pollock)

78. Time of Use Rates – Definition of On-Peak Period

Disputed between NSP and XLI. No other party provided testimony on this issue.

NSP position: the Company disagreed with the XLI proposal. The proposal is based on the system seasonal peak capacity differential, which is accurately recognized in the seasonal demand change differential and does not relate to energy and fuel cost charges.

XLI position: XLI recommended that the peak period be limited to summer months only, consistent with the Company's predominant summer capacity peak and the change to summer peak allocator in the CCOSS. XLI believed that customers should be provided an opportunity to actually respond to price signals through meaningful and sustained changes in their usage patterns, which is currently difficult based on a 12-hour peak period on all weekdays throughout the year.

Record Citations:
Huso Rebuttal, Exh. 107 at 44-45
Evidentiary Hearing Transcript, Vol. 2 at 172-175 (Huso)
Pollock Direct, Exh. 260 at 56-58
Pollock Surrebuttal, Exh. 263 at 39-42
Pollock Opening Statement, Exh. 264 at 4
Evidentiary Hearing Transcript, Vol. 3 at 35 (Pollock)

PART 6 – OTHER ICI GROUP ISSUES

79. Rate Shock

ICI Group position: the ICI Group opposed the additional rate increases as sought by the Company because the cumulative effect of five rate increases over the past ten years will cause "rate shock." The ICI Group also pointed out that the Company intends to file another general rate case seeking another rate increase in 2015. The result of such consistent and onerous rate increases will be to decrease the competitiveness of Minnesota businesses that compete in regional, national, and international markets. The consistent rate increases also lead to rates that are not "just and reasonable" as required by Minnesota Statutes.

Record Citations:
Glahn Direct, Exh. 250 at 3-5
Glahn Opening Statement, Exh. 254
Clark Direct, Exh. 99 at 10-13
Sparby Direct, Exh. 25 at 45

79A. MYRP in General

Disputed between NSP and ICI Group. No other party recommended not allowing MYRP.

NSP position: the Company recommended that the Commission accept the MYRP as proposed and modified by the Company during this proceeding. The Company proposed a multi-year rate plan as the best regulatory fit to reflect the current environment of significant investments. MYRP offers several benefits: greater rate predictability for customers, opportunities for rate moderation, regulatory efficiency, and long-term view of Company financials. The Company noted that MYRP provides additional benefits for customers, because the 2015 Step does not reflect the Company's full revenue requirement for 2015. The Company believed that MYRP will also provide benefits into 2016, as long as it is implemented in a manner that balances the interests of all Company stakeholders.

ICI Group position: the ICI Group opposed the Company's MYRP proposal for several reasons: the 2015 Step will get less scrutiny and lower-level review than a regular one-year rate case; the 2015 Step will move the Company from regulatory lag to regulatory lead and may allow the Company to over-earn if the U.S. economy improves; the inclusion of only Company-selected items in the 2015 Step tilts the playing field against customers who will not have access to the Company's entire 2015 financial data; and the process and reporting requirements for setting the 2015 Step rates are extremely complicated. The ICI Group believed that even with the risk of annual, consecutive rate cases, customers benefit from the transparency of having all revenue and expenses examined at one time in one proceeding. The ICI Group recommended that the Company's MYRP will be denied and the rates set in this proceeding based on 2014 test year costs and assets.

Record Citations:
Sparby Direct, Exh. 25 at 16-18
Sparby Rebuttal, Exh. 26 at 10-12
Clark Direct, Exh. 99 at 6-10
Clark Rebuttal, Exh. 100 at 2, 4-8
Heuer Direct, Exh. 88 at 6-7
Glahn Direct, Exh. 250 at 6-9
Glahn Surrebuttal, Exh. 251 at 1-2

PART 7 – OTHER CEI ISSUES

80. Inclining Block Rate (IBR)

Resolved among NSP, CEI, ECC and the Department. Also OAG and AARP provided testimony on this issue.

NSP, CEI, ECC, and the Suburban Rate Authority entered into a Stipulation Agreement on Inclining Block Rates during the Evidentiary Hearing. The Parties to the Stipulation requested that the Commission open a new docket and require the Company to file a proposal for an IBR rate structure, in a form of compliance filing, 120 days after the Commission issues its final order in this proceeding. All the evidence and arguments regarding the IBR from this case will be incorporated into the new docket.

Department position: the Department agreed that the IBR structure can be considered and implemented outside of a general rate case and noted that it no longer supported a requirement related to parallel billing for study purposes or to develop customer education means in this case. The Department also agreed to convene stakeholder meetings and review the Company's IBR proposal, as stated in the Stipulation Agreement, if the Commission so orders.

OAG position: the OAG noted that IBR programs can cause significant and detrimental unintended consequences, as demonstrated by CenterPoint Energy's IBR that was first suspended and then cancelled after further investigation. The OAG did not believe that the IBR proposed by CEI provides enough detail to ensure that it would not unfairly impact certain groups of customers. If the Commission chooses to move forward and consider an IBR, it would be appropriate to consider IBR in another proceeding, where multiple rate design proposals can be fully presented, analyzed, and compared. The OAG declined to enter into the Stipulation Agreement at this time.

AARP position: AARP did not recommend that the Commission approve inclining block rates in this docket.

Record Citations:
Sparby Rebuttal, Exh. 26 at 9-10
Clark Surrebuttal, Exh. 101 at 2-3, 7-8
Clark Opening Statement, Exh. 134 at 1
Evidentiary Hearing Transcript, Vol. 2 at 1115-117, 127-131, 138-143 (Clark)
Huso Rebuttal, Exh. 107 at 10-24
Huso Surrebuttal, Exh. 108 at 2-6
Grant Rebuttal, Exh. 416 at 1-6
Grant Opening Statement, Exh. 446 at 1-2
Evidentiary Hearing Transcript, Vol. 4 at 129-132 (Grant)
Nelson Rebuttal, Exh. 377 at 23-38
Nelson Surrebuttal, Exh. 378 at 20-21
Evidentiary Hearing Transcript, Vol. 3 at 266, 275-276 (Nelson)
Chernick Direct, Exh. 280 at 3-26
Chernick Surrebuttal, Exh. 295 1-14
Nissen Surrebuttal, Exh. 298 at 1-5
Chernick Opening Statement, Exh. 299 at 1-3
Evidentiary Hearing Transcript, Vol. 3 at 55-56, 57-58 (Chernick)
Colton Direct, Exh. 234 at 4-27
Colton Surrebuttal, Exh. 239 at 1-25
Colton Opening Statement, Exh. 242 at 1-3
Evidentiary Hearing Transcript, Vol. 3 at 12-16 (Colton)
Marshall Surrebuttal, Exh. 240 at 7-8, 10-11
Brockway Direct, Exh. 310 at 23
Stipulation on Inclining Block Rates, Exh. 135 at 1-7
Evidentiary Hearing Transcript, Vol. 2 at 115-117, 144-147

PART 8 – OTHER ECC ISSUES

81. Low-Income Renter Conservation Program

Resolved among NSP, ECC, the Department, and OAG. No other party provided testimony on this issue.

ECC position: ECC recommended that the Company should implement a low-income conservation program for renters who live in smaller housing units. There is substantial need and opportunity for promoting energy efficiency in low-income, one- to four-unit rental dwellings, and low-income renters are unable to invest in energy efficiency measures without financial assistance. In Surrebuttal, ECC agreed that the standard CIP process is appropriate for developing and implementing the low-income renter conservation program.

NSP position: the Company noted that it currently offers CIP programs that are also available for low-income renters in smaller housing units through Home Energy Savings Program (HESP) and Multi-Family Energy Savings Program (MESP). The Company is also currently evaluating and redefining its conservation programs and design options for the multi-family segment in the CIP process. The Company explained that this evaluation will also include addressing the need for program modifications or new programs for one- to four-unit rental properties. The Company agreed to modify its CIP plan once the new program is fully developed.
Department position: to the extent that the Company's current programs are available to low-income renters, they should be evaluated and utilized first before creating a new program. If a need is found to develop an additional CIP program for low-income renters who live in smaller housing units, the Department recommended ordering the Company to work with the Department CIP staff to develop such a program.

OAG position: the OAG agreed that low-income renters are one of the groups at most risk being negatively impacted by IBR and would also provide the largest marginal efficiency gains with respect to conservation investment. However, the ECC proposal lacks details and specificity (e.g., what is the form of assistance).

Record Citations:
Heuer Rebuttal, Exh. 90 at 36-37
Sundin Rebuttal, Exh. 42 at 16-18
Sundin Opening Statement, Exh. 118 at 2-3
Evidentiary Hearing Transcript, Vol. 1 at 143-144, 147-151 (Sundin)
Evidentiary Hearing Transcript, Vol. 2 at 120 (Clark)
Grant Rebuttal, Exh. 416 at 7
Peirce Surrebuttal, Exh. 422 at 13
Nelson Rebuttal, Exh. 377 at 31
Marshall Direct, Exh. 235 at 1-31
Marshall Rebuttal, Exh. 238 at 6-7
Marshall Surrebuttal, Exh. 240 at 1-3

PART 9 – OTHER

82. Reasonableness of the Company's Annual Incentive Compensation Program

The Commission's Ordering Paragraph 30 in its September 3, 2013 Findings of Fact, Conclusions, and Order in Docket No. E002/GR-12-961 directed that the Company "shall evaluate the goals set for its annual incentive program to determine if they are too lenient or if they actually require stretching to meet; the Company shall file the results of the evaluation in its next rate case." Department witness Mr. Lusti reported that, from his review of the Annual Incentive Compensation Reports for the years 2008-2012, he found that the Company's employees meet their KPI requirement goals nearly always. The Company's actual AIP compensation paid as a percentage of

AIP Target for the years 2010, 2011, 2012 and 2012 was 103 percent, 94 percent, 118 percent and 120 percent, respectively. The top twenty Company employees in 2013 received, as a group, 192 percent of target level compensation. Because this is a compliance issue of the Commission, the ALJ and the Commission will need to determine if the Company's AIP is reasonable.

Record Citations:
Lusti Direct, Exh. 437 at 56-59
Lusti Direct Attachments, Exh. 438, DVL-20, Schedule 2 and DVL-37

PART 1 – DEPARTMENT REVENUE REQUIREMENTS ISSUES

A. Disputed Department Issues – Revenue Requirements

1. Return on Equity (ROE)

Disputed among NSP, the Department, CEI, ICI Group, Commercial Group, and AARP. No other party provided testimony on this issue.

NSP position: the Company recommended an ROE of 10.25 percent, based on an analysis which supports a range of 10.00 percent to 10.70 percent, with a 80 percent/20 percent weighting of electric and combination company comparable groups. In Rebuttal Testimony, the Company continued to support its recommendation based on an updated analysis through May 30, 2014. The Company also explained ~~why~~ its position that it would be inappropriate to reduce the authorized ROE below the 9.80 percent proposed by the Department in Direct Testimony, citing the following factors: current financial market volatility and changing conditions; the two-year period during which the ROE will be in effect; the Company's ongoing need to fund substantial capital expenditures; and the likely negative effect on investors of a second successive decrease in the ROE, which would move the Company's ROE toward the bottom of ROE awards since August 2013. The Company also explained that the ICI Group's methodology and analysis are inconsistent with available data, based on an inappropriate comparable group and unsound applications, and not representative of NSPM's market-based cost of equity. The Commercial Group did not perform an independent analysis of the Company's cost of equity. The Company believed it is common to include Construction Work in Progress (CWIP) in rate base and CWIP does not warrant an adjustment to the ROE. It would also be inappropriate to reduce the Company's ROE in connection with its proposed decoupling mechanism, as proposed by AARP.

Department position: the Company did not show its proposed ROE to be reasonable. T~~t~~he Department originally recommended an ROE of 9.80 percent, the midpoint of a range of 8.97 percent to 10.62 percent, based on a 60 percent/40 percent weighting of the Final Electric Comparison Group (FEGC) and Final Combination Comparison Group (FCCG). In Surrebuttal, the Department recommended a 9.64 percent ROE, the midpoint of the updated range of 8.90 percent to 10.39 percent, based on an updated Discount Cash Flow (DCF) analysis for June 7, 2014 to July 7, 2014 and adjustments to the FECG and FCCG. The Department disagreed with the basis and positions of the ICI Group, because its comparison group was inaccurate and DCF analyses were flawed for several reasons. The Department also disagreed with the Commercial Group's recommendations because the information it used was outdated and CWIP does not justify an adjustment to the ROE. The Department also stated that the AARP proposal should be rejected, because the Company's comparison groups capture any decoupling impact on risk and therefore, no additional adjustment to the ROE is needed.

Formatted: Font: Garamond

CEI position: CEI stated that if the Commission approves a decoupling mechanism in this case, it should not change the Company's ROE for any reasons that are associated with the adoption of decoupling.

ICI Group position: the ICI Group recommended an ROE of 9.0 percent, based on its DCF analyses of comparable retail electric utility companies. The ICI Group stated that the 9.0 percent rate falls within the range of the decisions rendered and settlements approved by state regulators for comparable electric utilities in recent months.

Commercial Group position: the Commercial Group stated that the Company's requested ROE is higher than ROEs authorized by other jurisdictions (the average for vertically integrated utilities from 2012-2014 being 10.03 percent according to SNL Financial). The Commercial Group suggested that if CWIP is included in rate base, the ROE should be reduced because CWIP shifts risk from the Company to the ratepayers.

AARP position: AARP pointed out that decoupling shifts risks from shareholders to ratepayers, and the ROE in this case should be adjusted downward to reflect this shift. If decoupling is approved by the Commission, AARP recommended a 10-basis point reduction in ROE or setting ROE at the low end of the range of reasonable returns.

Record Citations:
Sparby Opening Statement, Exh. 113 at 3
Evidentiary Hearing Transcript, Vol. 1 at 30, 42-43, 48-49 (Sparby)
Hevert Direct, Exh. 27 at 2, 28-45, 54-56
Hevert Rebuttal, Exh. 28 at 2-58
Hevert Surrebuttal, Exh. 29 at 1-13
Hevert Opening Statement, Exh. 115 at 1-5
Evidentiary Hearing Transcript, Vol. 1 at 54-101 (Hevert)
Tyson Direct, Exh. 30 at 26
Amit Direct, Exh. 400 at 2-68~~44~~
Amit Rebuttal, Exh. 402 at 1-16
Amit Surrebuttal, Exh. 403 at 1-30~~8, 26-28~~
Amit Opening Statement, Exh. 443 at 1-4~~-2~~
Evidentiary Hearing Transcript, Vol. 4 at 31~~-35, 38~~-49 (Amit)
Evidentiary Hearing Transcript, Vol. 5 at 74 (Lusti)
Cavanagh Direct, Exh. 290 at 5-6
Cavanagh Rebuttal, Exh. 294 at 6
Cavanagh Opening Statement, Exh. 300 at 1
Evidentiary Hearing Transcript, Vol. 3 61-62, 68-71, 87-89 (Cavanagh)
Glahn Direct, Exh. 250 at 15-25
Glahn Surrebuttal, Exh. 251 at 4-5
Glahn Opening Statement, Exh. 254 at 1
Evidentiary Hearing Transcript, Vol. 3 at 111-135 (Glahn)
Chriss Direct, Exh. 225 at 8-9, 11
Brockway Direct, Exh. 310 at 18, 21-22
Brockway Rebuttal, Exh. 311 at 14-21
Brockway Surrebuttal, Exh. 312 at 6-8

2. Monticello LCM/EPU Project – Used and Useful (In-Service Date) (2014 and/or 2015 Step)

Partially resolved between NSP and MCC, disputed by the Department and XLI. No other party provided testimony on this issue.

NSP position: as part of its initial filing, the Company proposed to place the Monticello LCM/EPU Project into service as of January 2014 for regulatory accounting purposes. The Company believed its proposal is appropriate because the LCM/EPU Project is used and useful. The Company received the two required license amendments (EPU and MELLLA+) in December 2013 and March 2014, which means that the Company is currently operating under an amended license that allows operations at the increased 671 MWe level. The LCM/EPU Project equipment is currently in place, and used in current plant operations and power ascension to the increased level. Also, during the test year, the Company reached the first required data collection point and operated the plant at an uprated level of 640 MWe for approximately 20 days. The Company acknowledged there was a delay in the power ascension process, but confirmed its expectation that the plant will reach the full 671 MWe before the end of 2014. During the Evidentiary Hearing, the Company accepted the MCC proposal to defer the 2014 Monticello EPU depreciation expense and amortize the expense over the life of the facility (resulting in a $12.227 million decrease in the 2014 test year revenue requirements and $11.680 million increase in the 2015 Step revenue requirements). The Company requested to add $11.680 million in Monticello EPU costs to the 2015 Step. The Company recommended that the MCC proposal regarding purchased power costs be addressed in the annual automatic adjustment (AAA) Docket.

Department position: the Company did not show the reasonableness of its position. T~~t~~he Department stated that there are several uncertainties regarding the Monticello EPU in-service date, and facts do not support placing the EPU project into service during the test year since the plant is not yet used and useful. Specifically, the Department noted that the plant has operated at the reduced 600 MWe level since March 11, 2014, and is not operating at the higher 640MWe level, nor the full 671 MWe level. The EPU cannot be considered used and useful until the NRC allows the Company to resume power ascension testing and to operate the plant at the full 671 MWe. There are uncertainties regarding the NRC data review and the Department believed it was unlikely that the plant could resume power ascension testing in August 2014. Based on the facts in the case, the Department believed that Monticello EPU (71 MW) will not be available for most if not all of the 2014 test year. Also, human performance errors appear to have contributed to the power ascension testing issues and delays. The Department recommended disallowing the Monticello EPU depreciation expense and removing Monticello EPU from the rate base for the 2014 test year. If the Monticello EPU does not operate successfully at the full 671 MWe level by January 2015, the Department recommends that the EPU project be subject to the refund mechanism for the Multi-Year Rate Plan (MYRP). The Department disagreed with the MCC and Company proposal to remove and amortize depreciation and direct expenses over the life of the facility, because this approach would only shift costs onto ratepayers and increase future rates. The Department suggested that the issue of purchase power costs be addressed in the AAA Docket.

MCC position: MCC recommended: 1) treating the delay in operating the plant at the 671 MWe level as a mechanical failure consistent with the decision in the last rate case regarding Sherco Unit 3 outage, 2) removing the depreciation and direct expenses related to the Monticello EPU from the 2014 test year and amortizing them over the life of the facility, 3) removing and amortizing replacement fuel and power costs ($11,103,828), which could be tracked and refunded to rate payers through the Fuel Clause Adjustment (FCA) Rider, and 4) requiring the Company to provide status updates of the ascension to the 671 MWe uprate level. MCC believed that current ratepayers should pay either for the plant put in rate base or for the replacement power costs, but not both. MCC also

Formatted: Font: Garamond

Formatted: Font: Garamond

stated that if its recommendation is not accepted, then the entire EPU portion should be removed from the rate base until 2015 or later.

XLI position: XLI stated that the Monticello EPU will not be used and useful until the complete uprate of 71 MWe is in service and the plant can operate at that capacity on a sustainable basis. XLI recommended that the Commission make a proportional adjustment based on the date when the full 71 MWe is in service, for example, if the current credible estimate is December 2014, then revenue requirements associated with at least 11/12ths of the EPU costs should be removed from the 2014 test year.

Disputed amount: various. The Department: $31.284 million reduction in revenue requirements in 2014 and $18.901 million increase in revenue requirements in 2015 Step. MCC and the Company: $12.227 million reduction in revenue requirements in 2014 and $11.680 million increase in revenue requirements in 2015 Step (removing and amortizing the depreciation expense only). XLI: $28.551 million reduction in revenue requirements in 2014 and $26.406 million increase in revenue requirements in 2015 Step.

Record Citations:
Heuer Direct, Exh. 88 at 12
Heuer Rebuttal, Exh. 90 at 25-27, 31-32
Heuer Opening Statement, Exh. 140 at 3, 8
Evidentiary Hearing Transcript, Vol. 3 at 141, 147, 155-160 (Heuer)
Sparby Rebuttal, Exh. 26 at 17-18
Clark Rebuttal, Exh. 100 at 21-25
Clark Surrebuttal, Exh. 101 at 6-8
Clark Opening Statement, Exh. 134 at 1
Evidentiary Hearing Transcript, Vol. 2 at 112, 121-123 (Clark)
O'Connor Direct, Exh. 51 at 15-32
O'Connor Rebuttal, Exh. 53 at 2-19
O'Connor Surrebuttal, Exh. 55 at 1-5
O'Connor Opening Statement, Exh. 123 at 1-2
Evidentiary Hearing Transcript, Vol. 1 at 218-220, 227-235, 238-245 (O'Connor)
Perkett Direct, Exh. 92 at 13, 21-22
Perkett Rebuttal, Exh. 94 at 43-47, 54
Perkett Opening Statement, Exh. 130 at 2
Evidentiary Hearing Transcript, Vol. 2 at 56-57, 75-78, 82-86, 88-92 (Perkett)
Robinson Rebuttal, Exh. 97 at 19-21
Campbell Direct, Exh. 429 at 42-58
Campbell Surrebuttal, Exh. 435 at 32~~4~~-59
Campbell Opening Statement, Exh. 450 at 3
Evidentiary Hearing Transcript, Vol. 5 at 17-18, 30-32, 57-58 (Campbell)
Lusti Direct, Exh. 437 at 22, 39
Lusti Surrebuttal, Exh. 442 at 10, 41-42
Lindell Direct, Exh. 370 at 32-34
Schedin Direct, Exh. 340 at 3-9
Schedin Surrebuttal, Exh. 342 at 1-6
Evidentiary Hearing Transcript, Vol. 3 at 177-187 (Schedin)

Pollock Direct, Exh. 260 at 20-23
Pollock Surrebuttal, Exh. 263 at 20-23
Pollock Opening Statement, Exh. 264
Evidentiary Hearing Transcript, Vol. 3 at 29-30, 39-40 (Pollock)

3. Prairie Island Cancelled EPU Project (2014)

Resolved between NSP and the Department, disputed by OAG, MCC, and ICI Group. No other party provided testimony on this issue.

NSP position: the Company requested recovery of $66.1 million in expenses for the cancelled Prairie Island EPU project plus accrued AFUDC of $12.8 million (Total Company). The Company believed that the appropriate standard of review that should be applied to the Prairie Island cancelled EPU project is the prudence standard, which requires the Commission to determine whether the Company actions fell within a range of reasonableness based on the known circumstances at the time the actions were taken. The Company believed that the initiation, management, suspension, and cancellation of the Prairie Island EPU project were carried out in a prudent manner and resulted in reasonable costs for a project of this size, complexity, and regulatory requirements. The Company disagreed with the OAG's recommendation to disallow the $10.1 million pretax charge. The pretax charge is a financial reporting convention to recognize the uncertainty of full recovery of the EPU costs, required by Generally Accepted Accounting Principles (GAAP). During the Evidentiary Hearing, the Company and Department agreed to the Department's alternative proposal to amortize the Prairie Island EPU project costs over the remaining life of the facility with a debt-only return of 2.24 percent ($4.867 million reduction in revenue requirements).

Department position: the Department agreed that the Commission has allowed recovery of cancelled project costs in other rate cases as long as they were prudently incurred. All the costs requested by the Company should be recoverable because the requested amount is far less than the project costs proposed in the Certificate of Need Docket and the Company filed a timely Notice of Changed Circumstances with the Commission. The Department agreed that the EPU costs totaling $66.1 million and AFUDC costs totaling $12.8 million are eligible for recovery. However, the Department recommended that the $78.9 million to be recovered over the remaining life of the facility (20.3 years), without a return on the asset, because this adjustment provides a reasonable sharing of the costs between shareholders and ratepayers. If the Commission will allow a debt-only return on the asset, it should be 2.24 percent, reflecting the capitalization ratio for debt, and be fixed at this amount. During the Evidentiary Hearing, the Company and Department agreed to the Department's alternative proposal to amortize the Prairie Island EPU projects costs over the remaining life of the facility with a debt-only return of 2.24 percent.

OAG position: the OAG noted that the Company did not timely inform the Commission and Parties about the increasing risks and reduced benefits that it had identified internally and it took until October 2012 for the Company to revise its position and file for the cancellation of the Certificate of Need. The OAG believed that because the Company failed to timely cancel the EPU project, some of the project costs were excessive and imprudent. The Company also wrote off $10.1 million of EPU project costs in 2012, and this amount should not be eligible for recovery in this rate case. The OAG recommended that the Company should be denied recovery of $10.1 million equal to the amount of the write-off plus $12.8 million (Total Company) of AFUDC accrued in 2011-2012 when the EPU project was no longer viable and ongoing. In addition, the OAG recommended that any allowed costs be recovered over a 10-year period without a return on the asset.

MCC position: MCC recommended that the Company be allowed to recover the requested project costs and AFUDC over the remaining life of the facility (20.3 years) without earning an equity return on the asset, and with only half year recovery of the amortization expense in 2014. Under the circumstances of the project, ratepayers should not be required to pay an equity return on the asset. MCC did not oppose the Department's recommendation.

ICI Group position: ICI Group recommended that the Commission should deny recovery of all costs associated with the cancelled EPU project, because the EPU project was never a used and useful asset to ratepayers. If the Commission allows recovery of any project costs, these should be amortized over the remaining life of the facility without a return. If the Commission allows any return on the asset, it should be closer to a U.S. Treasury bill or bond interest rate than the Company's usual rate of return.

Disputed amount: various; $4.867 million reduction in revenue requirements (Company and Department), $4.398 million reduction in revenue requirements (OAG), $5.475 million reduction in revenue requirements (MCC), $8.595 million reduction in revenue requirements (ICI Group).

Record Citations:
Sparby Rebuttal, Exh. 26 at 20
Clark Direct, Exh. 99 at 30-41
Clark Rebuttal, Exh. 100 at 48-59
Clark Opening Statement, Exh. 134 at 1
Evidentiary Hearing Transcript, Vol. 2 at 112 (Clark)
Heuer Direct, Exh. 88 at 90-91
Heuer Rebuttal, Exh. 90 at 14-17, 33-34
Heuer Opening Statement, Exh. 140 at 1
Evidentiary Hearing Transcript, Vol. 3 at 139-140 (Heuer)
O'Connor Direct, Exh. 52 at 127-130
Evidentiary Hearing Transcript, Vol. 1 at 223-224 (O'Connor)
Alders Direct, Exh. 48 at 8-22
Alders Opening Statement, Exh. 121 at 1-2
Evidentiary Hearing Transcript, Vol. 1 at 187-193 (Alders)
McCall Direct, Exh. 49 at 12-39
McCall Opening Statement, Exh. 122 at 1-2
Evidentiary Hearing Transcript, Vol. 1 at 199-213 (McCall)
Weatherby Direct, Exh. 45 at 5-28
Weatherby Rebuttal, Exh. 47 at 1-9
Weatherby Opening Statement, Exh. 120 at 1-2
Evidentiary Hearing Transcript, Vol. 1 at 180-185, 193-198 (Weatherby)
Perkett Rebuttal, Exh. 94 at 31-36
Perkett Opening Statement, Exh. 130 at 2-3
Lusti Direct, Exh. 437 at 12-18
Lusti Surrebuttal, Exh. 442 at 3-7
Evidentiary Hearing Transcript, Vol. 5 at 83-84 (Lusti)

Lindell Direct, Exh. 370 at 35-44
Lindell Surrebuttal, Exh. 373 at 17-24
Lindell Opening Statement, Exh. 141 at 2
Evidentiary Hearing Transcript, Vol. 3 at 192-194, 216-217 (Lindell)
Schedin Direct, Exh. 340 at 10-11
Schedin Surrebuttal, Exh. 342 at 6-7
Glahn Direct, Exh. 250 at 10-12
Glahn Surrebuttal, Exh. 251 at 2-3

4. Qualified Pension – Discount Rate (2014)
5. Qualified Pension – 2008 Market Loss (2014)

Disputed between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company stated its selection of pension plan assumptions is subject to significant oversight by outside entities, their guidelines, and its own auditor. During the Evidentiary Hearing, the Company accepted the Department's recommendation that the Company should address in its initial filing of the next rate case why the Company's target asset allocations for its pension fund are reasonable, including ages of retirees and employees, and to address investment strategies and target asset allocations since 2007.

- XES Plan Discount Rate: the Company proposed a discount rate of 4.74 percent to determine the XES Plan pension expense. The calculation of the discount rate under FAS 87 for the XES Plan closely reflects market interest rates and a blended cost of a portfolio of high quality corporate bonds that match the timing of the Company's pension obligations. The proposed discount rate is representative of actual interest rates and is comparable to the average discount rates recently used by other utilities and large companies. Additionally, there has now been a long period of sustained low interest rates, and the primary reason to change the discount rate in the last rate case is no longer valid (i.e., abnormally low interest rates). Lastly, separating the discount rate calculation for financial accounting purposes and for ratemaking purposes is an artificial division between the Company's actual costs and allowed rate recovery. The economic conditions that lead to a lower discount rate for the XES Plan also support the low cost of long-term debt, and both should be reflected consistently.

- 2008 Market Loss: the Company has met its burden of proof and demonstrated that it would be appropriate to recover the 2008 Market Loss. The Company's qualified pension plans have been consistent in reflecting the prior years' pension gain or loss in the current year pension expense. Although NSPM Plan (using ACM) and XES Plan (using FAS 87) methods differ, basically all prior-period gains and losses are netted, and then the net amount either increases or decreases the asset value, which then is compared to future liabilities to determine the amount of unfunded liabilities. Treatment of the 2008 market and liability losses were no exception and followed these practices. The Company has calculated its qualified pension expense consistently, in accordance with Financial Accounting Standards Board and Commission standards, and has not included a separate adjustment for the 2008 Market Loss. The Company believed it would be inequitable to exclude part of the 2008 Market Loss from the qualified pension expense calculation, because the Company's customers have benefitted from large market gains in prior years, and did not pay any pension expense at all during several years before 2008. The Company has prudently managed its Pension trust investments, which must be diversified into different asset classes for the benefit of all pension plan participants, and these asset classes performed well in relation to their benchmarks.

Formatted: Indent: Left: 0.25", No bullets or numbering

- The Company proposed to continue to limit the XES Plan expense to the 2011 level cap of $6.1 million and defer the difference as well as extend the amortization period for prior-period gains and losses from 10 years to 20 years for the ACM portion (NSPM Plan) of pension. To the extent the Commission prefers a mechanism to further moderate the rate offset of the 2008 Market Loss, the Company also offered two slightly different proposals that would compare a five-year average, normalized qualified pension expense to the actual qualified pension expense each year, and use deferral for the difference for the period from January 1, 2014 to December 31, 2018. The Company believed that if the Commission is inclined to adopt some mechanism to moderate the qualified pension expense, it should adopt one of these alternative proposals instead of changing the discount rate for the XES Plan, which would create an artificial liability gain and depart from GAAP accounting.

Department position: the Company did not show the reasonableness of its position. T~~t~~he Department noted that the assumptions used to estimate pension costs should be reasonable and independently verifiable to ensure that the amount the ratepayers pay now for future employee benefits is reasonable. The Department attached the Towers Watson actuarial certificate which stated Xcel Energy (and not Towers Watson) selected the pension assumptions. The Department also recommended that the Commission require the Company to address in its initial filing of the next rate case why the Company's target asset allocations for its pension fund are reasonable, including ages of retirees and employees, and to address investment strategies and target asset allocations since 2007.

- XES Plan Discount Rate: the Department recommended setting the XES Plan discount rate at 7.25 percent for several reasons. The Department did not agree~~believe~~ that the XES Plan discount rate used by the Company is independently established. Furthermore, the Company's discount rate of 4.74 percent is artificially low compared to the EROA of 7.25 percent because it relies on a point-in-time measurement, ~~;~~ and because it is calculated based on an accounting method that is used for financial statement reporting purposes. The Department noted that the Aggregated Cost Method (ACM) for the NSPM plan relies on a longer-term prospective and already uses the same discount rate and EROA, consistent with pension funding methodology. The Department also believed that using a discount rate that is lower than the EROA artificially overstates pension expense for ratemaking purposes and is therefore unreasonable. There is no reason to use different discount rates and EROA rates, because the time period for discounting the pension liability to today's dollars and the EROA for determining future value of pension assets is the same time period, it is not reasonable for ratemaking to use different rates. The Department did not agree that raising the Company's expected discount rate in a rate case so that it equals the EROA would have a negative impact on the Company's funding as required by Employee Retirement Income Security Act (ERISA). Rather, ERISA's use of the same discount rate and EROA for funding purposes reaffirms the Department's recommendation regarding the appropriate discount rate to be used for test-year pension expense for determining rates to be charged to ratepayers in this rate case. Additionally, in the Company's last rate case, the Administrative Law Judge (ALJ) and Commission approved the method of using the same discount rate and EROA for the XES Plan. The Department opposed using an average of

Formatted: Font: Garamond

discount rates to determine the discount rate because the Company in the last rate case attempted to arbitrarily change its assumptions, which resulted in a very small adjustment when averaging.~~.~~ The Department's recommendation reduces the revenue requirements by 1.77 million (both O&M and capital).

- 2008 Market Loss: the Company did not show the reasonableness of its position. T~~t~~he Department recommended that the Company be allowed to recover only 50 percent of the 2008 market loss ($6.17 million reduction in O&M and capital expense). The Department stated that it would be unreasonable to require ratepayers to cover all of this~~e~~ extreme amount of $12.1 million for the 2008 market loss of $19.9 million pension expense in 2014. The Department was also concerned that despite the financial market returning to levels above pre-2008 market loss levels, the Company included over 60 percent of the 2008 market loss in the 2014 pension expense and attempted to get recovery of all of the 2008 market loss in the short term. The Department disagreed with the Company's claim of symmetry for pension, because when pension expense is negative in a rate case, the Company does not refund negative pension expense to ratepayers. Further, the Department stated that it is troubling that the ratepayers pay all the Company's generous pension plan expenses, because no contribution by employees result in the Company including 100 percent of pension expense in rates, including the four percent match of the 401K plan, plus all other benefits as provided on pages 104-107 of Campbell Direct. In addition, the Department disagreed that the Company showed it prudently managed pension assets and, in fact, raised concerns about the Company's management of its pension assets. ~~However, the Department recognized that the Company's pension plan liabilities have been larger than the pension plan assets in several recent years and also in 2014 and therefore some of the 2008 market loss should be included in the test year rates.~~

- If the Commission does not agree with the Department's recommendations, then the Department will support the Company's second alternative normalization proposal, with additional modification recommendations.

Disputed amount: $7.94 million adjustment and reduction in revenue requirements (both O&M and capital).

Record Citations:
Qualified Pension in General
Heuer Rebuttal, Exh. 90 at 17-20
Tyson Opening Statement, Exh. 116 at 2-3
Evidentiary Hearing Transcript, Vol. 1 at 105-107, 125-132 (Tyson)
Moeller Direct, Exh. 81 at 12-44
Schrubbe Rebuttal, Exh. 83 at 1-8
Evidentiary Hearing Transcript, Vol. 2 at 20 (Schrubbe)
Figoli Direct, Exh. 78 at 66-73
Wickes Rebuttal, Exh. 85 at 1-9
Campbell Direct, Exh. 429 at 99-119, 134-136, 171-173
Campbell Surrebuttal, Exh. 435 at 74-79, 88
Campbell Opening Statement, Exh. 450 at 4
Evidentiary Hearing Transcript, Vol. 5 at 21-22 (Campbell)

Discount Rate Assumption
Moeller Direct, Exh. 81 at 80-92
Schrubbe Rebuttal, Exh. 83 at 39-47
Schrubbe Opening Statement, Exh. 126 at 2-3
Evidentiary Hearing Transcript, Vol. 2 at 21-22, 26-30 (Schrubbe)
Tyson Rebuttal, Exh. 31 at 21-23
Campbell Direct, Exh. 429 at 114-119, 171-172
Campbell Surrebuttal, Exh. 435 at 79-87
Campbell Opening Statement, Exh. 450 at 5-6
Evidentiary Hearing Transcript, Vol. 5 at 39-44, 56-57, 66-68, 69-71 (Campbell)
Lusti Surrebuttal, Exh. 442 at 11

2008 Market Loss
Moeller Direct, Exh. 81 at 18-64
Schrubbe Rebuttal, Exh. 83 at 15-29
Schrubbe Opening Statement, Exh. 126 at 1-2
Evidentiary Hearing Transcript, Vol. 2 at 18-20, 31-34 (Schrubbe)
Wickes Rebuttal, Exh. 85 at 9-11
Tyson Rebuttal, Exh. 31 at 17-20 and Schedule 1
Tyson Opening Statement, Exh. 116 at 2-3
Evidentiary Hearing Transcript, Vol. 1 at 105-107, 125-132 (Tyson)
Campbell Direct, Exh. 429 at 124-134, 172-173
Campbell Surrebuttal, Exh. 435 at 89-95
Campbell Opening Statement, Exh. 450 at 6-7
Evidentiary Hearing Transcript, Vol. 5 at 33-39, 64-65, 68 (Campbell)
Lusti Surrebuttal, Exh. 442 at 11

Alternative Proposals
Schrubbe Rebuttal, Exh. 83 at 30-39
Evidentiary Hearing Transcript, Vol. 2 at 29-30 (Schrubbe)
Campbell Surrebuttal, Exh. 435 at 95-102
Campbell Opening Statement, Exh. 450 at 7-8

6. Retiree Medical Expenses (FAS 106) – Discount Rate and 2008 Market Loss (2014)

Disputed between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company requested recovery of $4.10 million in O&M expenses and $1.16 million in capital costs related to post-retirement medical expenses for certain employees who retired prior to 2000. The Company did not agree with the Department's recommendation to set the discount rate equal to the weighted average EROAs and to disallow 50 percent of the 2008 market loss for FAS 106 for the same reasons as for the Qualified Pension, as explained above.

Department position: the Company did not show the reasonableness of its position. T~~t~~o treat the 2008 market loss consistently, the Department recommended excluding 50 percent of the 2008 market loss costs from the FAS 106 medical expenses (O&M expense reduction of $88,500). Because the FAS 106 expense is calculated in the same manner as Qualified Pension expense under

FAS 87, the Department also recommended that the discount rate for FAS 106 should match the respective EROAs, 7.25 percent for the bargaining employee plan and 6.25 percent for the non-bargaining employee plan, for a weighted average discount rate of 7.11 percent (O&M expense reduction of $1,472,433). The Department proposed a corresponding proportional (54 percent) adjustment to FAS 106 capital costs. In Surrebuttal, the Department accepted the Company's calculation of the revenue requirement effects.

Disputed amount: $1.59 million adjustment and reduction in revenue requirements (both O&M and capital)

Record Citations:
Heuer Rebuttal~~Direct~~, Exh. 90~~88~~ at 21-22
Moeller Direct, Exh. 81 at 12, 114-117, 120-121
Schrubbe Rebuttal, Exh. 83 at 29, 47, 60
Figoli Direct, Exh. 78 at 77-78
Byrne Direct, Exh. 423 at 37-43
Byrne Surrebuttal, Exh. 427 at 12, 22-24, 28-29
Byrne Opening Statement, Exh. 449 at 1
Evidentiary Hearing Transcript, Vol. 5 at 10-13 (Byrne)
Lusti Direct, Exh. 437 at 20, 37
Lusti Surrebuttal, Exh. 442 at 8

7. Paid Leave / Total Labor (2014)

Disputed between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company requested recovery of $49.906 million in paid leave costs. In its Rebuttal Testimony, the Company explained that paid leave (or paid time-off) is not an independent cost or budget item, but rather a component of the total base labor cost, which is made out of Productive Labor and Non-Productive Labor. The actual amount of paid leave varies depending on how much paid time-off employees take during a year – if they take less time as paid leave than budgeted, the actual paid leave amount is lower but total base labor costs do not change. The Company believed an accurate analysis of budget-to-actual results should focus on the Company's Total Labor expense. The Company's actual Total Labor costs exceeded the budget for the period from 2011 and 2013, and the increases in Nuclear and Business Systems Total Labor costs alone account for virtually all of the Department's proposed adjustment of $5.6 million.

Department position: the Company did not show the reasonableness of its position. T~~t~~he Department pointed out that the Company has over-recovered paid leave expenses in the 2011 ($5.1 million) and 2013 ($4.0 million) rate cases. The Department initially recommended allowing a 3.7 percent increase to the actual 2013 paid leave costs to determine the reasonable test year 2014 amount. In Surrebuttal, the Department modified its position to address total labor costs as recommended by the Company, and recommended a downward adjustment of $5.6 million based on the Company's Total Labor expense. The Department calculated the $5.6 million adjustment by starting with 2012 actual labor expense and allowing an annual increase of 3 percent for 2013 and an additional 3 percent for 2014 (note the labor trend from 2011 to 2012 showed a 3 percent increase). ~~,~~ ~~allowing a 3 percent year-to-year increase from 2012 to 2014.~~ The Department stated that this

Formatted: Font: Garamond

Formatted: Font: Garamond

Formatted: Font: Garamond

normalizing approach was reasonable, since the 2013 actual labor costs were abnormally high (12.2 percent increase over 2012 actual labor costs) due to extended nuclear outages as noted by the Company and unusually high number of ~~significant~~ storms as noted by the Department.

Disputed amount: $5.6 million adjustment and reduction in revenue requirements

Record Citations:
Stitt Direct, Exh. 86 at 37-38
Stitt Rebuttal, Exh. 87 at 1-9
Stitt Opening Statement, Exh. 129 at 1-2
Campbell Direct, Exh. 429 at 95-98, 108-109, 171
Campbell Surrebuttal, Exh. 435 at 69-74
Campbell Opening Statement, Exh. 450 at 4
Evidentiary Hearing Transcript, Vol. 5 at 32-33 (Campbell)
Lusti Direct, Exh. 437 at 42
Lusti Surrebuttal, Exh. 442 at 33

8. Rate Case and Monticello Prudency Review Expense Amortization (2014)

Partly disputed between NSP and the Department. No other party provided testimony on the issue.

NSP position: the Company proposed to amortize the 2014 rate case expense over a two-year period, since it would most likely file its next rate case in 2015, using a 2016 test year. The Company believed that a two-year amortization period is appropriate also for the Monticello prudence review costs. These are one-time expenses that should not be considered as capital costs since they do not add to plant in service, do not affect the plant operations in any way, and are not large enough to amortize over a longer time period. It would be inappropriate to require recovery of these costs over a 16.8-year period without a return on the asset.

Department position: the Company did not show the reasonableness of its position. T~~t~~he Department agreed on the amount of rate case and prudence expenses that the Company requested to recover. It also agreed on the two-year amortization period for the rate case expenses. The Department opposed the two-year amortization period for prudence review expenses and stated that these costs should be spread over the remaining life of the Monticello facility, which is 16.8 years, without a return. The Commission is reviewing the prudency of planning and constructing the facility, and the decision will continue for the life of the facility, not until the next rate case is filed as is the case with rate case expenses.

Disputed amount: $418,452 adjustment and reduction in revenue requirements.

Record Citations:
Heuer Direct, Exh. 88 at 142-143
Heuer Rebuttal, Exh. 90 at 23-25
Lusti Direct, Exh. 437 at 27-29
Lusti Surrebuttal, Exh. 442 at 16-18
Lusti Opening Statement, Exh. 451 at 1

9. MYRP: Rate Moderation Proposal – TDG Theoretical Depreciation Reserve Surplus (2014 and 2015 Step)[1]

Disputed among NSP, the Department, and OAG. No other party provided testimony on this issue.

NSP position: in the Company's last rate case, the Commission required amortization over eight years of the difference between the Company's recorded book depreciation reserve and the theoretical book reserve for the transmission, distribution, and general (TDG) assets. In this case, the Company proposed to accelerate return of the remaining theoretical depreciation reserve surplus to customers by amortizing it over the next three years: 50 percent in 2014, 30 percent in 2015, and 20 percent in 2016. The Company believed that its recommendation of using the theoretical reserve surplus in conjunction with the Department of Energy (DOE) settlement payment moderation proposal creates greater consistency and predictability in year-over-year increases in customer rates.

Department position: the Department recommended to return the remaining depreciation reserve surplus to customers by amortizing it over the next three years: 50 percent in 2014, 40 percent in 2015, and 10 percent in 2016, which would result in a $12.633 increase in revenues for 2015 and decrease in revenue requirements. Alternatively, the Department supported the Company's proposed 50-30-20 percent option, which would have a $0 impact. The Department noted that it did not support the give back of theoretical depreciation reserves in the last rate case and fundamentally does not support theoretical depreciation. However, in light of the Commission approval of the give back of theoretical depreciation reserve in the last rate case for transmission, distribution and general plant (using an eight year straight-line method), and the fact that the Commission approved in interim rates for this rate case the Company's give back proposal of 50 percent in 2014, 30 percent in 2015, and 20 percent in 2016, the Department's options for this rate case were limited unless the Department wanted to increase customers rates.

OAG position: the OAG believed that the Company's moderation proposal does not offer any real savings to customers, but simply shifts cost recovery into the future, which will result in higher costs later for future ratepayers. In addition, the moderation proposal violates the Commission's rules that require straight-line depreciation, and therefore requires a variance. The OAG recommended that the Commission should deny the change in the amortization of the depreciation reserve surplus proposed by the Company.

Disputed amount: see Heuer Rebuttal, Schedule 15 for revenue requirement comparisons. No impact for the Company's proposal (or Department's alternative proposal), except $10.1 million corrected DOE amount noted on issue no. 34 below. The Department's initial recommendation is a $12.633 million decrease in revenue requirements.

Record Citations:
Sparby Rebuttal, Exh. 26 at 12-13
Clark Direct, Exh. 99 at 27-29
Clark Rebuttal, Exh. 100 at 36-42
Heuer Direct, Exh. 88 at 8, 92-93, 154-155

[1] The rate moderation proposal regarding DOE Settlement Funds is discussed under issue no. 34 and Nuclear Theoretical Depreciation Reserve is discussed under issue no. 75.

Heuer Rebuttal, Exh. 90 at 28-29
Robinson Direct, Exh. 95 at 29-33
Robinson Rebuttal, Exh. 97 at 11-19
Robinson Opening Statement, Exh. 132 at 1
Evidentiary Hearing Transcript, Vol. 2 at 96, 108-110 (Robinson)
Perkett Direct, Exh. 92 at 36-40
Campbell Direct, Exh. 429 at 75-94, 88-90
Campbell Surrebuttal, Exh. 435 at 65-69
Campbell Opening Statement, Exh. 450 at 3-4
Lindell Direct, Exh. 370 at 11-16
Lindell Opening Statement, Exh. 141 at 1-2
Evidentiary Hearing Transcript, Vol. 3 at 190-192 (Lindell)

10. Depreciation and Plant Retirements in the 2015 Step – Passage of Time (2015 Step)

Disputed between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company did not believe a passage of time adjustment is appropriate or necessary in this case. The Company included a limited number of capital projects in the 2015 Step, and excluded a substantial number of other capital projects as well as most O&M items. The Department's recommendation expands the scope of the 2015 Step to cover rate base components and expenses that are decreasing without recognizing that other increasing costs are not included in the Step, which makes the recommendation asymmetrical. The Company also believed that the depreciation adjustment of $17.53 million recommended by the Department does not include both accumulated depreciation reserve and depreciation expenses. When both values are used, the total adjustment would increase the revenue requirements by $1.9 million. Similarly, if forecasted retirements for non-Step projects are accounted for in the 2015 Step revenue requirements calculations, then the annualized plant depreciation expense for all of the 2014 plant additions should be included as well.

Department position: the Company did not show the reasonableness of its position. T~~t~~he Department believed it is appropriate to reflect total plant depreciation expense and related accumulated depreciation for the passage of time from 2014 to 2015 for those projects that are not included in the 2015 Step (but are included in the 2014 test year). Similarly, 2015 plant retirements should be accounted for in the 2015 Step. These are known and measurable changes that decrease expenses, and the language in the Commission's Order in the Multi-Year Rate Plan Docket supports these adjustments that are capital and capital related adjustments. Depreciation is the actual capital investment being spread over the life of the facilities. The Department stated it is unfair and inequitable to allow the Company to reflect a nearly $70 million revenue requirement increase for ~~selected~~ 36 capital projects (which represent 81.3 percent of all possible 2015 capital projects and 72.4 percent of the 2015 Step) and related depreciation expenses in the 2015 Step without reflecting the Company's reduced total plant depreciation expense, related accumulated depreciation, and plant retirements for the passage of time from 2014 to 2015 in the 2015 Step. Not capturing the step down in rate base due to the normal passage of time and including know 2015 retirements being paid for by ratepayers via 2014 rate base is one-sided. In addition, the 2015 Step is hardly limited, since the Company captured over 80 percent of the full 2015 forecasted increase in rate base. The Department raised concerns about using 2014 rate base amounts that are generally higher than other years and then adding on top of this the incremental 2015 rate base amounts, where 2015 is already a high rate base year. That approach is like adding two peaks together and asserting the sum of the two peaks is the new peak, even though the first peak declined. The Department also noted that in information request no. 2113 the Department requested the Company to update all depreciation for the passage of time, which would include all changes in depreciation expense and depreciation reserve, as discussed on page 163 and (NAC-32) of Ms. Campbell's Direct Testimony, and is not one-sided as suggested by the Company. The Department stated that the forecasted 2015 transmission and distribution plant retirements reduce the revenue requirements in the 2015 Step by $535,552, and updating depreciation expense and accumulated depreciation reserve for all plant in rate base for 2015 (except for the specific 2015 Step capital projects) reduce the 2015 revenue requirements by $17.53 million. The Department recommended these two adjustments.

Disputed amount: $18.07 million adjustment and reduction in revenue requirements for 2015 Step.

Record Citations:
Sparby Rebuttal, Exh. 26 at 11-12, 14-16
Sparby Opening Statement, Exh. 113 at 2
Evidentiary Hearing Transcript, Vol. 1 at 30, 50-51 (Sparby)
Clark Rebuttal, Exh. 100 at 33-34
Clark Opening Statement, Exh. 134 at 1-2
Evidentiary Hearing Transcript, Vol. 2 at 113-114, 119 (Clark)
Perkett Rebuttal, Exh. 94 at 3-7
Perkett Opening Statement, Exh. 130 at 2
Evidentiary Hearing Transcript, Vol. 2 at 57 (Perkett)
Campbell Direct, Exh. 429 at 156-165, 175-177
Campbell Surrebuttal, Exh. 435 at 109-120
Campbell Opening Statement, Exh. 450 at 10-11
Evidentiary Hearing Transcript, Vol. 5 at 27-28, 45-54, 58-63, 65 (Campbell)
Lusti Direct, Exh. 437 at 48-49
Lusti Surrebuttal, Exh. 442 at 39-40

11. Changes to In-Service Dates for Capital Projects (2014 and 2015 Step)

Disputed between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company did not believe it is appropriate to include an adjustment for changes to the in-service dates for capital projects. In any given year, the Company expects a certain amount of movement in in-service dates, as priorities change, some projects are delayed or cancelled, and other projects emerge. The Company believed the 2014 test year is representative of the projects that will go into service in 2014 and therefore there is no need to adjust for changes to in-service dates for a limited number of individual projects. As it pertains to the 2015 Step, in addition to the reasons discussed above, the Company did not believe an in-service date adjustment is needed since the refund mechanism applicable to MYRP already provides customer protections, and the 2015 Step projects represent a limited percentage of the Company's total 2015 budgeted cost.

Department position: the Company did not show the reasonableness of its position. T~~t~~he Department believed that the most current information for in-service dates for capital projects included in the test year 2014 and 2015 Step should be used to determine reasonable rates. The Department disagreed with the Company that it is appropriate to add new capital projects, ~~'s argument that reallocating capital budget to refund~~ like-kind replacements and other replacement projects would justify making no adjustments when in-service dates move outside the test year (49 projects) and ~~or~~ Step year (2 projects). Allowing additional capital projects into the rate case at this time would unfairly burden Parties and be against the ALJ's First Prehearing Order, which limits introducing new information to this rate case. The Company has the opportunity to put forth its best case in its initial rate case filing. The Department stated that 49 capital projects included in the 2014 test year and 2 capital projects included in the 2015 Step now have revised in-service dates outside 2014 and 2015, and recommended making corresponding adjustments.

Disputed amount: $2.18 million reduction in revenue requirements for test year 2014; $2.05 million reduction in revenue requirements for 2015 Step.

Record Citations:
Sparby Rebuttal, Exh. 26 at 14-15
Clark Rebuttal, Exh. 100 at 12-19
Perkett Direct, Exh. 92 Schedule 8
Perkett Rebuttal, Exh. 94 at 38-42
Evidentiary Hearing Transcript, Vol. 2 at 72-75 (Perkett)
Stitt Opening Statement, Exh. 129 at 1-2
Evidentiary Hearing Transcript, Vol. 2 at 37-38 (Stitt)
Mills Rebuttal, Exh. 60 at 19-21
O'Connor Rebuttal, Exh. 53 at 46-49
Campbell Direct, Exh. 429 at 150-154, 174
Campbell Rebuttal, Exh. 434 at 102-109
Campbell Opening Statement, Exh. 450 at 8-9
Lusti Surrebuttal, Exh. 442 at 12, 39

B. Resolved Department Issues – Revenue Requirements

12. Capital Structure and Cost of Debt (2014 and 2015 Step)

Resolved between NSP and the Department, disputed by ICI Group. No other party provided testimony on this issue.

The Company and the Department agreed that the Company's capital structure, as updated in Rebuttal Testimony, is reasonable and appropriate for test year 2014 (52.50 percent Equity, 45.60 percent long-term debt, and 1.90 percent short-term debt) and for Step year 2015 (52.50 percent Equity, 45.61 percent long-term debt, and 1.89 percent short-term debt). The Company and the Department also agreed that the updated capital structure and cost of debt (5.52 percent for test year 2014 and 6.06 percent for 2015 Step) should be incorporated into this case. The Company and the Department further agreed that the Company's capital structure is reasonably comparable to the capital structures of comparable companies and is appropriate in light of the Company's levels of infrastructure investments and capital market conditions. The Company and the Department also agreed that NSPM's capital structure is an actual, separate capital structure that is market-based and reflects a separate capital structure in financial reporting and communications with financial markets, and therefore ICI Group's recommendation should be rejected.

ICI Group position: the ICI Group recommended that the Company be allowed to include common equity in its capital structure only up to the actual amounts employed by the parent company Xcel Energy Inc., 47.5 percent in 2014 and 49.0 percent in 2015.

Record Citations:
Heuer Opening Statement, Exh. 140 at 3, 8
Evidentiary Hearing Transcript, Vol. 3 at 141-142, 147 (Heuer)
Tyson Direct, Exh. 30 at 3-6, 26-38, 25-30
Tyson Rebuttal, Exh. 31 at 1-11
Tyson Opening Statement, Exh. 116 at 1
Evidentiary Hearing Transcript, Vol. 1 at 103-105, 124-125
Hevert Direct, Exh. 27 at 53-54
Hevert Rebuttal, Exh. 28 at 3, 8-17
Hevert Opening Statement, Exh. 115 at 1
Evidentiary Hearing Transcript, Vol. 1 at 54 (Hevert)
Amit Direct, Exh. 400 at 44-56
Amit Rebuttal, Exh. 402 at 14-15
Amit Opening Statement, Exh. 443 at 1-2
Evidentiary Hearing Transcript, Vol. 4 at 35-36 (Amit)
Glahn Direct, Exh. 250 at 25-26
Glahn Surrebuttal, Exh. 251 at 5-7

13. Sales Forecast (2014 and 2015 Step)

Resolved among NSP, the Department, and MCC. No other party provided testimony on this issue.

NSP position: in Rebuttal, the Company proposed to use the 2014 weather-normalized actual sales data to establish 2014 test year sales in this proceeding, which would eliminate the need, for example, to determine the appropriate Demand Side Management (DSM) adjustment or customer counts. The Company initially objected to the Department's proposal to also reflect the sales for a new large commercial and industrial customer in 2015 but subsequently agreed to the adjustment for this customer. The Company agreed to use the Department's coefficients to weather-normalize the 2014 test year sales and committed to work with the Department to ensure that the calculations are correct. In case the Commission will not approve the proposal to use actual sales data, the Company recommended adopting its Rebuttal sales forecast, which uses weather-normalized actual sales from January through May 2014 and projections from June through December, including a DSM adjustment. The Company also agreed to work with the Department and other stakeholders on the use of the price variable or other aspects of the sales forecast model in the future.

During the Evidentiary Hearing, the Company proposed to submit the first 11 months of sales data and the related revenue calculations on December 16, 2014 to allow sufficient time for review and comment. The Company proposed to submit the December 2014 actual sales data no later than January 16, 2015. The Company can also submit forecasted December sales data in its December filing, which would then include 11 months of actual sales data and one month of forecasted sales data.

Department position: the Department agreed with the Company's Rebuttal and Evidentiary Hearing proposal to calculate the test year sales based on a full year of 2014 actual, weather-normalized sales data, to include the addition of a new large commercial and industrial customer in 2015, and to use the Department's calculations and coefficients to weather-normalize the test year 2014 sales. If any forecasted data is used for December 2014 sales, the Department recommended using values from its updated forecast, not the Company's. In case the Commission will not approve the use of actual 2014 sales data, the Department recommended using its updated sales forecast for setting final rates. But if the Commission uses the Company's updated sales forecast for setting final rates, the Department recommended using the Company's updated sales forecast as corrected by the Department in Surrebuttal Testimony.

MCC position: during the Evidentiary Hearing, MCC accepted the proposal by the Company and the Department to use the 2014 actual, weather-normalized sales, including the addition of a new large commercial and industrial customer in 2015, to establish 2014 test year sales in this proceeding.

Record Citations:
Heuer Opening Statement, Exh. 140 at 5-6
Evidentiary Hearing Transcript, Vol. 3 at 143-144 (Heuer)
Sparby Rebuttal, Exh. 26 at 19
Marks Direct, Exh. 38 at 1-52
Marks Rebuttal, Exh. ~~3~~40 at 1-21
Hyde Direct, Exh. 43 at 1-10
Hyde Rebuttal, Exh. 44 at 1-7
Hyde Opening Statement, Exh. 119 at 1-2
Evidentiary Hearing Transcript, Vol. 1 at 168-179 (Hyde)
Sundin Rebuttal, Exh. 42 at 6-15
Sundin Opening Statement, Exh. 118 at 1-2
Evidentiary Hearing Transcript, Vol. 1 at 140-143, 163-164 (Sundin)
Shah Direct, Exh. 404 at 1-31
Shah Surrebuttal, Exh. 406 at 1-21, SS-S-5[2]
Shah Opening Statement, Exh. 444 at 1
Evidentiary Hearing Transcript, Vol. 4 at 51-55 (Shah)
Lusti Direct, Exh. 437 at 43
Lusti Surrebuttal, Exh. 442 33, 44
Evidentiary Hearing Transcript, Vol. 5 at 84-86 (Lusti)
Maini Direct, Exh. 343 at 6-14
Maini Surrebuttal, Exh. 345 at 5-10
Maini Opening Statement, Exh. 145 at 1
Evidentiary Hearing Transcript, Vol. 4 at 11, 13 (Maini)

[2] Attachment SS-S-5 was initially labeled SS-S-1 in Department Exh. 406 (Shah Surrebuttal). The Department corrected this reference at the Evidentiary Hearing.

Formatted: Font: Garamond, 11 pt

Formatted: Font: Garamond, 11 pt

14. Property Tax Amount (2014)

Resolved between the NSP and the Department. Also MCC provided testimony on this issue.

NSP position: the Company originally requested $149.2 million in property tax expenses for the 2014 test year. In Rebuttal, the Company validated the accuracy of its initial 2014 forecast by using updated information and based on the validated data, expected the 2014 total Company property tax expense to be $145.1 million. During the Evidentiary Hearing, the Company agreed to reduce the 2014 test year property tax amount to $141.0 million (a $9.0 million reduction), as recommended by the Department in Surrebuttal, subject to a true-up for actual 2014 property taxes. Under the true-up proposal, the total 2014 test year property tax would be capped at $145.0 million (Minnesota electric jurisdiction). There is no downward limit on the true-up.

The Company and the Department agreed on the following procedure for the property tax true-up: the Company will file its year-end 2014 property tax expense with the Commission on January 16, 2015, based on Truth in Taxation Notices received in November and December of 2014. The Commission would reflect the 2014 year-end property tax expense in its determination of the Company's 2014 revenue requirement and the 2014 year-end property tax expense would be reflected in final rates in this case, up to a cap of $145.0 million (Minnesota electric jurisdiction). The Company will also make a compliance filing on June 30, 2015 detailing the final 2014 property tax expense reflected on property tax statements received in the spring of 2014. If the 2014 property tax expense reflected on the property tax statements is less than the year-end 2014 property tax expense (i.e., the 2014 test year property tax expense), the Company will make ongoing annual refunds of the difference until the Company files the next rate case.

Department position: the Department initially recommended reducing the 2014 test year property tax expense by 9 percent ($13.5 million). In Surrebuttal, the Department recommended reducing the 2014 test year property tax by $14.0 million, which reflects a test year property tax expense of $136.0 million, based on an average increase of 10.72 percent in property tax expense for each year from 2009 to 2013. Alternatively, the Department recommended a reduction of $9.0 million, based on the percent difference between the Company's initial 2014 test year forecast presented in Direct Testimony and the validated 2014 property tax presented in Rebuttal Testimony and including a further adjustment related to the difference between the Company's June 2013 forecast of 2013 property taxes and actual 2013 property taxes. During the Evidentiary Hearing, the Department accepted the Company's proposal to reduce the 2014 test year property tax amount to $141.0 million, subject to a true-up for actual 2014 property taxes and a cap of $145.0 million.

MCC position: MCC believed that the most current information available, as provided in IR MCC-248, should be used to estimate the property tax amount, resulting in an adjustment of $5.9 million. Alternatively, MCC accepted the Department's proposal presented in Direct Testimony.

Adjustment: $9.0 million reduction in revenue requirements, subject to true-up, with ultimate expense capped at $145.0 million.

Record Citations:
Heuer Opening Statement, Exh. 140 at 2
Evidentiary Hearing Transcript, Vol. 3 at 140, 161-164, 168-169 (Heuer)

Duevel Direct, Exh. 32 at 1-2, 5-14
Duevel Rebuttal, Exh. 34 at 2-11
Duevel Opening Statement, Exh. 117 at 1
Evidentiary Hearing Transcript, Vol. 1 at 136-139 (Duevel)
Lusti Direct, Exh. 437 at 36
Lusti Surrebuttal, Exh. 442 at 24-30
Lusti Opening Statement, Exh. 451 at 2
Evidentiary Hearing Transcript, Vol. 5 at 75-76 (Lusti)
Schedin Direct, Exh. 340 at 21-22
Schedin Surrebuttal, Exh. 342 at 11-12

15. Emissions Control Chemical Costs (2014)

Resolved between NSP and the Department. No other party provided testimony on this issue.

NSP position: in its initial filing, the Company requested recovery of approximately $10.30 million for emissions control chemical costs for the test year (Minnesota electric jurisdiction). The Company believed its 2014 test year budget for emissions control chemicals is reasonable, based on appropriate factors, and responsive to similar concerns raised by the Department in the last rate case. During the Evidentiary Hearing, the Company accepted the Department's recommended downward adjustment of $2.265 million for chemical costs.

Department position: the Department noted that the Company has over-recovered emissions control chemical costs each year since 2009, and believed that using historical averages of the Company's actual emission chemical costs provides more accurate results than the Company's forecasts. The Department recommended using a three-year historical average of prior emissions costs (adjusted for Sherco 3 outage and upcoming chemical use at Sherco 1 and 2) and proposed a downward adjustment of $2.265 million for the Minnesota electric jurisdiction ($1.876 million for other than Sherco chemical costs and $0.389 million for Sherco chemical costs).

Adjustment: $2.265 million reduction in revenue requirements.

Record Citations:
Heuer Opening Statement, Exh. 140 at 1
Evidentiary Hearing Transcript, Vol. 3 at 140 (Heuer)
Mills Direct, Exh. 58 at 16-29
Mills Rebuttal, Exh. 60 at 3-10
Mills Opening Statement, Exh. 125 at 1
Evidentiary Hearing Transcript, Vol. 2 at 11-12 (Mills)
Robinson Rebuttal, Exh. 97 at 25
Campbell Direct, Exh. 429 at 10-26, 165-166
Campbell Surrebuttal, Exh. 435 at 21-28
Campbell Opening Statement, Exh. 450 at 2
Lusti Direct, Exh. 437 at 40
Lusti Surrebuttal, Exh. 442 at 32

16. Insurance – Surplus Distributions from Industry Mutual Insurance Pools (2014)

Resolved between NSP and the Department. No other party provided testimony on the issue.

NSP position: the Company did not include the Nuclear Electric Insurance Limited (NEIL) and Energy Insurance Mutual (EIM) surplus distributions in the 2014 test year in its initial filing~~ because the recent distributions have been irregular~~. In Rebuttal, the Company agreed that ~~since the NEIL and EIM distributions were received prior to the closing of the record in this case, ~~it is appropriate to include these distributions as an offset to the 2014 test year budget.

Department position: the Department listed several reasons why it believed it is unreasonable to exclude the NEIL and EIM surplus distributions form the 2014 test year and recommended a corresponding adjustment.

Adjustment: $1.662 million reduction in revenue requirements.

Record Citations:
Heuer Rebuttal, Exh. 90 at 12-13
Anderson Direct, Exh. 35 at 14-18
Anderson Rebuttal, Exh. 37 at 2-3
Byrne Direct, Exh. 423 at 22-27
Byrne Surrebuttal, Exh. 427 at 11
Lusti Direct, Exh. 437 at 39
Lusti Surrebuttal, Exh. 442 at 32

17. Treatment of Capitalized Pension and Related Benefit Costs – Rate Base Factor Method (2014)

Resolved between NSP and the Department. No other party provided testimony on this issue.

The Company proposed to use the method developed in the last rate case to determine pension and related benefit O&M expenses. This method applies a rate base factor to the beginning-of-year/end-of-year average of the capitalized portion of costs and thus converts the capital adjustments to revenue requirement. The Department accepted the Company's proposal.

Record Citations:
Heuer Rebuttal, Exh. 90 at 18-20
Campbell Surrebuttal, Exh. 435 at 74-75

18. Qualified Pension – Measurement Date Update (2014)

Resolved between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company believed that the same measurement date should be used to calculate all pension and benefit expenses, including qualified pension. The Company recommended using December 31, 2013 as the measurement date because it provides the most current information available.

Department position: the Department did not initially accept the Company's proposal to update the measurement date for the qualified pension because the Company had not initially supported the increase in pension expense due to "unfavorable demographic experience" and the lower 7.01 percent actual return on assets compare to the 7.25 percent EROA for 2013. Additionally, the ~~update~~ increased ~~the~~ pension expense was unexpected due to how well the financial market performed in 2013. ~~and because the Department had concerns about the financial performance of the pension assets.~~ In Surrebuttal, the Department accepted the Company's proposal to update the measurement date for the qualified pension to December 31, 2013.

Adjustment: $1.011 million increase in revenue requirements (both O&M and capital).

Record Citations:
Heuer Rebuttal, Exh. 90 at 19-20
Schrubbe Rebuttal, Exh. 83 at 8-15
Tyson Rebuttal, Exh. 31 at 15-21
Campbell Direct, Exh. 429 at 120-124, 172
Campbell Surrebuttal, Exh. 435 at 87-89
Campbell Opening Statement, Exh. 450 at 5
Lusti Surrebuttal, Exh. 442 at 11-12

19. Retiree Medical Expenses (FAS 106) – Measurement Date Update (2014)

Resolved between NSP and the Department. No other party provided testimony on this issue.

The Company and the Department agreed to update the measurement date for FAS 106 to December 31, 2013.

Adjustment: $666,522 reduction in revenue requirements.

Record Citations:
Heuer Rebuttal, Exh. 90 at 21-22
Schrubbe Rebuttal, Exh. 83 at 8-11, 60
Byrne Direct, Exh. 423 at 40-41, 43
Byrne Surrebuttal, Exh. 427 at 11-12
Byrne Opening Statement, Exh. 449 at 1

20. Non-Qualified Pension – Restoration Plan (2014)

Resolved between NSP and the Department. No other party provided testimony on the issue.

NSP position: the Company explained that its Restoration Plan provides supplemental benefits to those employees whose wages exceed the IRS-determined compensation limits in order to give them equal level of benefits than those employees who can participate in qualified pension plans. Restoration Plans are a common practice in the electric industry and other American businesses. In Rebuttal, the Company accepted the Department's recommendation to disallow Restoration Plan costs for this case.

Department position: the Department recommended that the Commission disallow all Restoration Plan costs because it is not reasonable for ratepayers to finance these benefits. The Company's Restoration Plan provides a generous tax benefit, which exceeds the amounts allowed by the Internal Revenue Service, to employees who are already highly compensated. Also, the Commission has disallowed the recovery of non-qualified and supplemental pension costs in recent rate cases.

Adjustment: $704,000 reduction in revenue requirements (both O&M and capital).

Record Citations:
Heuer Direct, Exh. 88 at 142
Heuer Rebuttal, Exh. 90 at 21
Moeller Direct, Exh. 81 at 12, 108-113
Figoli Direct, Exh. 78 at 73-76
Figoli Rebuttal, Exh. 80 at 13-17
Campbell Direct, Exh. 429 at 105-110, 136-145, 174
Campbell Surrebuttal, Exh. 435 at 12-14
Campbell Opening Statement, Exh. 450 at 1
Lusti Direct, Exh. 437 at 41
Lusti Surrebuttal, Exh. 442 at 11-12

21. Post-Employment Benefits – Long-Term Disability and Workers' Compensation (FAS 112) (2014)

Resolved between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company requested recovery of $3.79 million in O&M expenses and $190,152 in capital costs related to post-employment benefits (primarily long-term disability and workers' compensation) for former or inactive employees after employment but before retirement. In Rebuttal, the Company agreed on the Department's recommendation to update the measurement date to December 31, 2013.

Department position: the Department agreed on the Company's proposed discount rate of 3.74 percent and recommended updating the measurement date to December 31, 2013. In Surrebuttal, the Department accepted the Company's calculation of the revenue requirement effects.

Adjustment: $421,463 reduction in revenue requirements (both O&M and capital).

Record Citations:
Heuer Rebuttal, Exh. 90 at 22-23
Moeller Direct, Exh. 81 at 12, 117-121
Schrubbe Rebuttal, Exh. 83 at 60
Byrne Direct, Exh. 423 at 43-47
Byrne Surrebuttal, Exh. 427 at 13
Lusti Direct, Exh. 437 at 37
Lusti Surrebuttal, Exh. 442 at 8-9

22. Active Health Care and Welfare Costs (2014)

Resolved between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company believed its method of calculating active health care and welfare costs is appropriate and the costs are reasonable and representative of the test year 2014. The calculations were based on the 2011 and 2012 actual health and welfare costs, adjusted for plan changes, inflation, and claim trends. During the Evidentiary Hearing, the Company accepted the Department's downward adjustment of $1.082 million.

Department position: the Department recommended adjusting the active health care expenses because the Company has over-recovered health care costs in the recent past and because other factors indicated that health care costs would not increase as much as the Company had forecasted in its 2014 test year. ~~the Department believed the costs were over-estimated.~~ The Department initially recommended using a three-year average of 2011-2013 actual health care costs to calculate the 2014 test year amount, and a corresponding proportional (9.1 percent) adjustment to all health care and welfare capital costs. In Surrebuttal, the Department modified its recommendation to use an inflation factor of 2.85 percent over 2013 claims expenses, which resulted in a total expense of $35.387 million and a corresponding proportional adjustment in capital costs. The Department also requested that in its next rate case filing, the Company is required to provide historical active health care costs since 2011 for each calendar year, including both book and claims expenses and Incurred But Not Reported (IBR) accruals and reversals.

Adjustment: $1.082 million reduction in revenue requirements (both O&M and capital)

Record Citations:
Heuer Opening Statement, Exh. 140 at 2
Evidentiary Hearing Transcript, Vol. 3 at 140-141 (Heuer)
Moeller Direct, Exh. 81 at 112, 128-134
Schrubbe Rebuttal, Exh. 83 at 47-60
Evidentiary Hearing Transcript, Vol. 2 at 12 (Mills)
Schrubbe Opening Statement, Exh. 126 at 1
Evidentiary Hearing Transcript, Vol. 2 at 18 (Schrubbe)
Figoli Direct, Exh. 78 at 57-65
Byrne Direct, Exh. 423 at 27-37
Byrne Surrebuttal, Exh. 427 at 13-21, 27-28
Byrne Opening Statement, Exh. 449 at 3~~1~~
Evidentiary Hearing Transcript, Vol. 5 at 9 (Byrne)
Lusti Direct, Exh. 437 at 38
Lusti Surrebuttal, Exh. 442 at 9

23. Nuclear Cash-Based Retention Program (2014)

Resolved between NSP and the Department. No other party provided testimony on the issue.

NSP position: the Company stated that the Nuclear Cash-Based Retention Program is a vital program necessary to attract new employees and to retain current employees in highly specialized and critical positions in the competitive nuclear labor market. The Company also explained that the retention program and Annual Incentive Plan (AIP) serve different purposes and provide separate compensation for different goals and time periods. During the Evidentiary Hearing, the Company accepted the Department's proposal to remove all the costs associated with the Nuclear Retention Program from the test year.

Department position: the Department stated it is reasonable to conclude that the Nuclear Retention Program was created in 2012 to provide some of the Company's nuclear employees additional compensation ~~and~~ to replace ~~the~~ amounts they would likely not receive via the traditional incentive compensation (the AIP), until such time as the nuclear business unit as a whole could achieve a high Key Performance Indicator (KPI) rating.~~otherwise have received through the AIP. The Department recommended removing all the costs associated with the Nuclear Retention Program from the test year.~~

Adjustment: $516,466 reduction in revenue requirements.

Record Citations:
Heuer Opening Statement, Exh. 140 at 2
Evidentiary Hearing Transcript, Vol. 3 at 141 (Heuer)
Figoli Direct, Exh. 78 at 50-55
Figoli Rebuttal, Exh. 80 at 10-13
O'Connor Direct, Exh. 51 at 99-105
O'Connor Rebuttal, Exh. 53 at 19-29
O'Connor Opening Statement, Exh. 123 at 1-2
Evidentiary Hearing Transcript, Vol. 1 at 218 (O'Connor)
Lusti Direct, Exh. 437 at 29-35
Lusti Surrebuttal, Exh. 442 at 19-24

24. Customer Care O&M Expenses – Miscellaneous O&M Credits (2014)

Resolved between NSP and the Department. No other party provided testimony on the issue.

NSP position: the Company accepted the Department's recommendation that the Miscellaneous O&M Credits be set at $1.216 million, because this amount closely correlates with the Company's current budget forecast for 2014. The Company did not believe that the use of historical average is appropriate for this type of expense.

Department position: the Department pointed out that the Company has over-recovered Customer Care O&M expenses by $3.2 million from 2011 to 2013. Almost half of this is accounted by the Meter Reading O&M and specifically under-estimation of the Miscellaneous O&M Credits. Based on information provided regarding the Company's contract with Cellnet, t~~T~~he Department recommended that the Company's 2014 test year Miscellaneous O&M Credits to be set at the amount of the average Miscellaneous O&M Credits from 2010 through 2013, at $1.216 million.

Adjustment: $503,142 reduction in revenue requirements.

Record Citations:

Heuer Rebuttal, Exh. 90 at 12
Gersack Direct, Exh. 71 at 10, 16-17
Gersack Rebuttal, Exh. 72 at 1-6
Byrne Direct, Exh. 423 at 10-17, 49
Byrne Surrebuttal, Exh. 427 at 5-7
Lusti Direct, Exh. 437 at 38
Lusti Surrebuttal, Exh. 442 at 31

25. Nuclear Fees (2014)

Resolved between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company disagreed with the Department's original recommendation to allow only a 1.1 percent increase in nuclear fees from 2013, because the Department used the abnormally low 2013 Nuclear Regulatory Commission (NRC) actual fees for the starting point and because all other than NRC fees increased about 10 percent from 2011 to 2013. The Company also explained that in June 2014, the NRC updated the pre-reactor portion of its 2014 Annual Fee at 19 percent higher than in 2013 ($15.8 million). This increase alone justifies the Company's test year 2014 nuclear fee amount. During the Evidentiary Hearing, the Company agreed to reduce the amount of other than NRC nuclear fees and accepted the Department's final recommended adjustment of $1.00 million.

Department position: the Department recommended that the 2014 test year nuclear fees should be reduced because the average year-to-year increase in nuclear fees has been 1.1 percent from 2011 to 2013. In Surrebuttal, the Department agreed with the Company on the NRC fees based on the 2014 final fee rule by NRC which significantly increased nuclear fees by over 19 percent and recommended allowing the requested amount of $15.00 million for the Minnesota jurisdiction. However, the Department continued to believe that many of the other nuclear fees were overstated, and recommend a $1.00 million downward adjustment to other nuclear fees.

Adjustment: $1.00 million reduction in revenue requirements

Record Citations:
Heuer Rebuttal, Exh. 90 at 27-28
Heuer Opening Statement, Exh. 140 at 2
Evidentiary Hearing Transcript, Vol. 3 at 140 (Heuer)
O'Connor Direct, Exh. 51 at 112-117
O'Connor Rebuttal, Exh. 53 at 29-41
O'Connor Opening Statement, Exh. 123 at 1-2
Evidentiary Hearing Transcript, Vol. 1 at 218 (O'Connor)
Campbell Direct, Exh. 429 at 67-75, 170
Campbell Surrebuttal, Exh. 435 at 59-65
Campbell Opening Statement, Exh. 450 at 2
Lusti Direct, Exh. 437 at 42
Lusti Surrebuttal, Exh. 442 at 32

26. Investor Relations Costs (2014)

Resolved between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company requested recovery of 50 percent of investor relations costs with the exception of requesting recovery for all stock registration fees for the Minnesota electric jurisdiction. The Company believed that this request accommodated concerns expressed in the prior rate cases. In Rebuttal, the Company accepted the Department's recommendation to remove 50 percent of all investor relations expenses, including the stock registration fees.

Department position: the Department stated that the Company's request does not comply with the Commission's Order in the last rate case, which excluded 50 percent of all investor relations expenses from the test year. The Department recommended that 50 percent of the entire amount of investor relations costs, including the stock registration fees, be removed from the test year.

Adjustment: $78,140 reduction in revenue requirements.

Record Citations:
Heuer Direct, Exh. 88 at 139
Heuer Rebuttal, Exh. 90 at 13
Stitt Direct, Exh. 86 at 60-61
Tyson Direct, Exh. 30 at 38-44
Tyson Rebuttal, Exh. 31 at 30
Byrne Direct, Exh. 423 at 7-10, 48-49
Byrne Surrebuttal, Exh. 427 at 4-5
Lusti Direct, Exh. 437 at 38
Lusti Surrebuttal, Exh. 442 at 31

27. Nuclear Refueling Outage Cost Amortization (2015 Step)

Resolved between NSP and the Department; disputed between NSP and OAG. No other party provided testimony on this issue.

NSP position: the Company believed an adjustment for decreased nuclear outage costs in the 2015 Step is unnecessary and inappropriate. The Company included a limited number of capital projects in the 2015 Step, and excluded a substantial number of other capital projects as well as most O&M items. The OAG recommendation also expands the scope of the 2015 Step to cover rate base components and expenses that are decreasing without recognizing that other increasing costs are not included in the Step. The Company also pointed out that nuclear amortization expense is a separate O&M item, which is not directly related to any of the capital projects included in the 2015 Step.

Department position: the Department noted in its Direct Testimony that the amortization expenses for nuclear refueling outages decreased by $7.5 million from 2014 to 2015, yet the Company did not include this reduction in the 2015 Step to benefit the ratepayers. The Department stated that a corresponding downward adjustment ($5.5 million for the Minnesota electric jurisdiction) is reasonable to balance the representation of the 2015 costs of the nuclear facilities and to account for known and measurable decreases in expenses (in contrast to only increases). In Surrebuttal, the

Department agreed that nuclear outage costs related to O&M fuel outage expenses (for which the Company received special approval so they could amortize these expenses between fuel outages in Docket No. E002/M-07-1489) are not capital costs, as initially believed in Direct Testimony. As a result, the Department ~~are separate O&M expenses that are not directly related to any of the 2015 Step capital projects, and~~ no longer recommended the $5.5 million adjustment for nuclear outage expenses.

OAG position: the OAG supported the original recommendation and arguments made by the Department in its Direct Testimony. The OAG also stated that the nuclear refueling outage expense is a known and measurable decrease, and it should not be treated differently because of MYRP.

Disputed amount: $5.5 million adjustment and reduction in revenue requirements for 2015 Step (OAG Recommendation).

Record Citations:
Sparby Rebuttal, Exh. 26 at 11-12
Clark Rebuttal, Exh. 100 34-35
Clark Surrebuttal, Exh. 101 at 3-6
O'Connor Direct, Exh. 51 at 118-127
O'Connor Surrebuttal, Exh. 55 at 2-3
Campbell Direct, Exh. 429 at 61-67, 169-170
Campbell Surrebuttal, Exh. 435 at 14-17
Campbell Opening Statement, Exh. 450 at 1
Lusti Direct, Exh. 437 at 53
Lusti Surrebuttal, Exh. 442 at 43
Lindell Rebuttal, Exh. 372 at 5-6
Lindell Opening Statement, Exh. 141 at 2
Evidentiary Hearing Transcript, Vol. 3 at 194-195 (Lindell)

28. Business Systems General Ledger (G/L) System (2015 Step)

Resolved between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company stated it is on track with the G/L project milestones and confident that it can meet the cutover deadline December 31, 2015, when the G/L system will be placed in service and used for its intended purpose. The Company decided to designate December 31, 2015 as the official cutover to the new G/L system to align with the Company's financial year-end date. The Company also explained that the new G/L system will be operationally ready on November 1, 2015 and be used parallel with the JDE system in November and December 2015. During the parallel operation, the new G/L system has completed all testing and is processing live financial transactions, running reports, and executing business processes.

Department position: the Department initially recommended removing the G/L replacement project costs ($20.36 million) from the 2015 Step. The Department stated the Company has not shown that the system will be used and useful for Minnesota ratepayers until January 1, 2016, because the G/L system will be in a testing environment in the fourth quarter of 2015 and will not be placed into service until the last day of 2015. In Surrebuttal, the Department agreed that the G/L system will be in service on December 31, 2015 and no longer recommended the adjustment.

Record Citations:
Harkness Direct, Exh. 62 at 48-52
Harkness Rebuttal, Exh. 64 at 1-12
Perkett Rebuttal, Exh. 94 at 50-51
Robinson Rebuttal, Exh. 97 at 8
Byrne Direct, Exh. 423 at 18-22
Byrne Surrebuttal, Exh. 427 at 7-10
Campbell Direct, Exh. 429 at 154
Lusti Direct, Exh. 437 at 47
Lusti Surrebuttal, Exh. 442 at 38

29. Prairie Island Site Administration Building (2015 Step)

Resolved between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company believed that any adjustments to the Prairie Island administrative building project costs or in-service date were unnecessary. The Company included $22.6 million (Total Company) for the Prairie Island administration building capital costs in the 2015 Step, however, this amount covered also other additional work that was not included in the scope of the competitive bid. The Company explained that it expects to receive the certificate of occupancy in December 2014, and from that day the building will be used and useful. Also the gradual move-in process is planned to begin in December 2014.

Department position: in Direct, the Department noted that the total amount of $22.6 million for the Prairie Island administrative building project is more than the competitive bid that was selected, and the Company has not provided support for the amount that exceeds the selected bid. The Department also recommended changing the in-service date from December 31, 2014 to March 1, 2015, since the Company will complete punch list items in January 2015 and plans to move the staff to the new building in March 2015. In Surrebuttal, the Department agreed with the Company because the Company supported the additional costs and the Company indicated that it would now be moving some employees into the building in December 2014. Therefore, the Department ~~and~~ no longer recommended the downward capital cost adjustment or the change in the in-service date for the PI administrative building.

Record Citations:
O'Connor Direct, Exh. 51 at 69-70
O'Connor Rebuttal, Exh. 53 at 42-44
O'Connor Opening Statement, Exh. 123 at 1
Perkett Rebuttal, Exh. 94 at 48-50
Robinson Direct, Exh. 95 at 8-11
Robinson Rebuttal, Exh. 97 at 8
Campbell Direct, Exh. 429 at 154-156
Campbell Surrebuttal, Exh. 435 at 17-20
Campbell Opening Statement, Exh. 450 at 2

Lusti Direct, Exh. 437 at 49
Lusti Surrebuttal, Exh. 442 at 10, 41

30. Pleasant Valley Wind and Border Winds (2015 Step)
31. Ratepayer Protection Mechanism for Company-Owned Wind Farm Costs

Resolved between NSP and the Department. Also the OAG and MCC provided testimony on this issue.

NSP position: the Company accepted the Department's recommendation that the base rates for the 2015 Step should include estimated Production Tax Credits (PTCs), subject to true-up in the RES Rider. However, the Company was also open to include both the capital costs and PTCs for Pleasant Valley and Border Winds in the Renewable Energy Standard (RES) Rider. The Company clarified that the difference between the capital expenditure numbers in Mr. Mill's and Mr. Robinson's testimonies was due to AFUDC and the Strategist modeling in the Wind Acquisition Dockets included AFUDC. The Company stated that MCC's proposal to limit recovery to 1-2 months does not reflect how rate base is calculated using beginning of year/end of year averages. In addition, the methodology used should be consistent for all capital additions calculations. Given the limited time, the Company believed that this case is not the best forum to develop a ratepayer protection mechanism for Company-owned wind farm costs, and proposed to work with MCC and other Parties prior to January 1, 2015 and report results in the RES Rider Docket.

Department position: the Department originally stated that the Company has not shown why it is reasonable to recover capital costs for the Pleasant Valley and Border Winds projects in excess of the amounts that were approved in the Wind Acquisition Dockets and believed that the costs were overstated in the 2015 Step. In Surrebuttal, the Department accepted the Company's explanation of discrepancies between Mr. Mills' testimony and Mr. Robinson's testimony due to AFUDC (since the AFUDC was included in the strategist model, which was approved by the Commission) and no longer proposed a downward adjustment of $5,672,482 for capital project costs. The Department recommended that the base rates for the 2015 Step should include estimated PTCs ($11.093 million), subject to true-up in the RES Rider. The Department stated it would prefer to include the recovery of the capital costs in this rate case, but did not oppose to recover them in the RES Rider, particularly if the Company will not otherwise increase rates in 2016.

OAG position: the OAG supported the original arguments and recommendations made by the Department in its Direct Testimony, including the downward adjustment of $5,672,482 and treatment of PTCs.

MCC position: MCC stated its concern of the in-service dates for the Pleasant Valley Wind and Border Winds projects, which will be late in 2015. MCC initially recommended removing all the capital costs related to these two wind projects from the 2015 Step, alternatively, the Commission should limit recovery to only those 1-2 months that the projects will be in service in 2015. In Surrebuttal, MCC recommended that the Company should recover the costs for the two wind projects through the RES Rider and supported the Company's proposal to work with MCC and other Parties regarding a ratepayer protection mechanism that addresses cost overruns for Company-owned wind farms. MCC recommended that the Commission include an Order point with a process and timeline regarding the ratepayer protection mechanism, so that interested Parties may participate on a timely basis.

Disputed amount: $5,672,482 million reduction in revenue requirements (OAG Recommendation).

Record Citations:
Sparby Rebuttal, Exh. 26 at 20
Clark Rebuttal, Exh. 100 at 26-29
Mills Direct, Exh. 58 at 61-66
Mills Rebuttal, Exh. 60 at 11-15
Robinson Direct, Exh. 95 at 11-13, 37-38
Robinson Rebuttal, Exh. 97 at 3-7
Robinson Opening Statement, Exh. 132 at 1-2
Evidentiary Hearing Transcript, Vol. 2 at 96 (Perkett)
Perkett Rebuttal, Exh. 94 at 52-53
Campbell Direct, Exh. 429 at 32-42
Campbell Surrebuttal, Exh. 435 at 2-12
Campbell Opening Statement, Exh. 450 at 1
Lusti Direct, Exh. 437 at 47, 51
Lusti Surrebuttal, Exh. 442 at 39
Lindell Rebuttal, Exh. 372 at 3-5
Maini Direct, Exh. 343 at 2-6
Maini Surrebuttal, Exh. 345 at 1-4
Evidentiary Hearing Transcript, Vol. 4 at 13-16, 19-22 (Maini)

32. Property Tax Amount (2015 Step)

Resolved between NSP and the Department. No other party provided testimony on this issue.

NSP position: in Rebuttal, the Company proposed to include in the 2015 Step only those property tax expenses that are directly associated with the capital projects in the 2015 Step. This resulted in a $3.309 million adjustment and reduction in the revenue requirements.

Department position: the Department recommended reducing the 2015 Step property tax expense by 9 percent to reflect the cumulative difference between the Company's actual property taxes and the amounts included in rates over a thirteen-year period. In Surrebuttal, the Department accepted the $3.309 million adjustment proposed by the Company.
Adjustment: $3.309 million reduction in revenue requirements.

Record Citations:
Heuer Rebuttal, Exh. 90 at 29
Clark Rebuttal, Exh. 100 at 9
Robinson Direct, Exh. 95 at 23-25
Robinson Rebuttal, Exh. 97 at 8-10
Duevel Direct, Exh. 32 at 3-5, 15-18
Duevel Rebuttal, Exh. 34 at 12-13
Lusti Direct, Exh. 437 at 36, 54

Lusti Surrebuttal, Exh. 442 at 45

33. Emissions Control Chemical Costs (2015 Step)

Resolved between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company believed its mercury sorbent budget in the 2015 Step is based upon the best information available, however, the Company acknowledged that there is some uncertainty around estimating the use of mercury sorbent at Sherco Units 1 and 2. In Rebuttal, the Company agreed that non-capital costs in the 2015 Step should be directly related to capital projects and agreed to remove chemical costs associated with A.S. King and Sherco Unit 3 from the 2015 Step ($180,000 adjustment). During the Evidentiary Hearing, the Company agreed to further reduce the amount of chemical costs and remove an additional $1.40 million, resulting in a total adjustment of $1.58 million.

Department position: the Department originally recommended excluding half of the 2015 emissions control chemical costs ($2.98 million for the Minnesota electric jurisdiction). The Department stated that the Company has a pattern of over-estimating emissions control chemical costs, and there is added uncertainty because the use of mercury sorbent at Sherco 1 and 2 will be a new experience for the Company. In addition, the Department noted that the chemical costs associated with A.S. King and Sherco Unit 3 are not directly related to new capital upgrades and therefore should not be included in the 2015 Step. During the Evidentiary Hearing, the Department accepted the final $1.58 million adjustment proposed by the Company.

Adjustment: $1.58 million reduction in revenue requirements.

Record Citations:
Heuer Opening Statement, Exh. 140 at 7
Evidentiary Hearing Transcript, Vol. 3 at 146-147 (Heuer)
Sparby Rebuttal, Exh. 26 at 12, 20-21
Clark Direct, Exh. 99 at 16-17
Clark Rebuttal, Exh. 100 at 9, 30-32
Mills Direct, Exh. 58 at 39-40
Mills Rebuttal, Exh. 60 at 3-10
Mills Opening Statement, Exh. 125 at 1
Evidentiary Hearing Transcript, Vol. 2 at 12 (Mills)
Robinson Direct, Exh. 95 at 27-28, Schedule 12.
Robinson Rebuttal, Exh. 97 at 8-10
Campbell Direct, Exh. 429 at 26-32, 166
Campbell Surrebuttal, Exh. 435 at 28-31
Campbell Opening Statement, Exh. 450 at 2
Lusti Direct, Exh. 437 at 53
Lusti Surrebuttal, Exh. 442 at 44

34. MYRP: Rate Moderation Proposal – DOE Settlement Funds (2015 Step)

Resolved between NSP and the Department, disputed by OAG and Commercial Group. No other party provided testimony on this issue.

NSP position: the Company proposed to use the DOE settlement funds received in 2013 and 2014 in excess of the annual decommissioning accrual requirements as a moderation mechanism to reduce the 2015 revenue deficiency. The Company agreed with the adjustment proposed by the Department and stated that the current amount of DOE settlement payments available for rate moderation is approximately $25.74 million. The Company believed that its recommendation for using the DOE settlement payments in conjunction with the Theoretical Reserve moderation proposal creates greater consistency and predictability in year-over-year increases in customer rates. During the Evidentiary Hearing, the Company agreed to true-up and refund to customers any DOE payments received in excess of the amount reflected in the Commission's final Order for the 2015 Step.

Department position: the Department raised concerns about using the DOE settlement funds as a moderation mechanism, but did not oppose using the DOE funding in excess of the current decommissioning accrual at this time and for purposes of this rate case. The Department noted that according to the Company's response in discovery, the DOE payments will be approximately $10 million less than estimated by the Company in its initial filing and recommended a corresponding adjustment. During the Evidentiary Hearing, the Department agreed that the Company had provided support for the reduced DOE payment amount of $25.74 million, and agreed with the Company's ~~continued to recommend a~~ $10.1 million adjustment (decrease in DOE refund revenues, so increase in revenue requirements).

OAG position: the OAG recommended that the Commission carefully consider whether the Company's moderation proposal is reasonable and in the public interest. The OAG stated that using DOE refunds to lower rates does not produce any real savings to ratepayers, since the DOE refunds belong to the ratepayers regardless of the type of mechanism that is used to return them.

Commercial Group position: the Commercial Group recommended that the Commission approve the use of excess DOE payments for rate increase moderation, however, funds received in 2013 should be used to moderate the rate increase for the 2014 test year and funds received in 2014 should be used to moderate the rate increase for the 2015 Step.

Adjustment: $10.1 million increase~~reduction~~ in revenue requirements (Company and Department).

Record Citations:
Sparby Rebuttal, Exh. 26 at 12-13
Clark Direct, Exh. 99 at 28-29
Clark Rebuttal, Exh. 100 at 36-42
Heuer Direct, Exh. 88 at 8, 155
Heuer Rebuttal, Exh. 90 at 28-29
Heuer Opening Statement, Exh. 140 at 7
Evidentiary Hearing Transcript, Vol. 3 at 147, 149-151, 165-166 (Heuer)
Robinson Direct, Exh. 95 at 33-34

Robinson Rebuttal, Exh. 97 at 11-19
Perkett Direct, Exh. 92 at 43
Perkett Opening Statement, Exh. 130 at 1
Evidentiary Hearing Transcript, Vol. 2 at 55 (Perkett)
Campbell Direct, Exh. 429 at 75-94
Campbell Surrebuttal, Exh. 435 at 65-69
Campbell Opening Statement, Exh. 450 at 3-4
Lindell Direct, Exh. 370 at 11-16
Chriss Direct, Exh. 225 at 12

35. MYRP: Refund Mechanism Due to Postponed or Cancelled Capital Projects

Resolved between NSP and the Department. No other party provided testimony on this issue.

NSP position: during the Evidentiary Hearing, the Company proposed a refund mechanism for both 2014 test year and 2015 Step. The Company's understanding is that the Department supports the mechanism, which is based on the difference between the Commission approved revenue requirements and actual revenue requirements associated with capital additions. For the 2014 test year, the mechanism will start with the Commission approved 2014 test year plant related base revenue, but exclude the 2014 plant additions for the Monticello LCM/EPU project or 2015 Step projects (Adjusted Test Year 2014 Plant Related Revenue Requirements). The mechanism would then compare the Adjusted Test Year 2014 Plant Related Revenue Requirements to the actual plant related base rate revenue requirements, again excluding the 2014 plant additions for the Monticello LCM/EPU project or 2015 Step projects (Adjusted Actual 2014 Plant Related Revenue Requirements). If the Adjusted Actual 2014 Plant Related Revenue Requirements is lower than the Adjusted Test Year 2014 Plant Related Revenue Requirements, the Company will include the amount in the interim rate refund and the calculation of final rates in 2015. The Company will submit a compliance filing prior to the implementation of final 2014 rates that

- calculates the Adjusted Actual 2014 Plant Related Revenue Requirements and compares it to the Adjusted Test Year 2014 Plant Related Revenue Requirements,
- compares the 2014 test year to the 2014 actual capital additions, and
- provides an explanation for all project capital additions that were included in actual rate base but not part of the 2014 test year.

A similar refund process will be used for the 2015 Step, however, limited only to the projects included in the 2015 Step.

Department position: the Department recommended that the Company be required to reduce rates for capital projects that do not occur within the 2014 test year or 2015 Step year, and refund to its customers all rates that have been over-collected as a result of the cancellation of projects. Although the first year of MYRP is developed similarly as a traditional rate case, it is tied to MYRP and the standard for ratepayer protection must be increased accordingly. During the Evidentiary Hearing, the Company and Department agreed to a refund mechanism for the 2014 test year and 2015 Step.

Record Citations:
Clark Direct, Exh. 99 at 20-22
Clark Rebuttal, Exh. 100 at 12-14, 19-20

Heuer Opening Statement, Exh. 140 at 3-4
Evidentiary Hearing Transcript, Vol. 3 at 142-143, 152-154 (Heuer)
Perkett Opening Statement, Exh. 130 at 1-2
Evidentiary Hearing Transcript, Vol. 2 at 55, 78-81, 86-88, 93 (Perkett)
Lusti Direct, Exh. 437 at 68-71
Lusti Surrebuttal, Exh. 442 at 47-49

36. MYRP: Compliance for 2015 Step Projects

During the Evidentiary Hearing, the Company proposed the following process in compliance with the Commission's June 17, 2013 Multi-Year Rate Plan Order:

The 2015 Step rates will be set consistent with the Commission's final Order in this proceeding. The Company will provide quarterly compliance reporting during 2015 (April, August, November) to the Commission comparing the most current forecast of each 2015 Step project to the amount included in the 2015 Step. By April 1, 2016, the Company will submit its final compliance report which will include:

- The actual 2015 Step revenue requirement for each project, specifically 2014 actual, 2015 actual and the difference (2015 Step);
- The revenue requirement difference for each 2015 Step project between the 2015 Step actual and 2015 Step test year;
- Explanations for project additions that are greater than included in the 2015 Step;
- In the event the total actual 2015 Step revenue requirement is lower than the total test year 2015 Step revenue requirement, the Company will include in its compliance filing a proposal for rate refund;
- In the event the Company becomes aware of a 2015 Step project cancellation or postponement, the Company will provide 30 day notice including a refund plan.

Record Citations:
Heuer Opening Statement, Exh. 140 at 6-7
Evidentiary Hearing Transcript, Vol. 3 at 145-146 (Heuer)

37. Service Agreement Between NSP and Xcel Energy Services, Inc.

Resolved between NSP and the Department. No other party provided testimony on this issue.

The Company filed on March 24, 2014 a petition to amend the Service Agreement between the Company and Xcel Energy Services, Inc. (Docket No. E,G002/AI-14-234). The Company and the Department agree that any changes that result from the Commission's Order in that Docket should be incorporated into this case.

Record Citations:
Stitt Rebuttal, Exh. 87 at 13-14
Byrne Direct, Exh. 423at 3-5, 48
Byrne Surrebuttal, Exh. 427 at 2-3
Byrne Opening Statement, Exh. 449 at 1
Evidentiary Hearing Transcript, Vol. 5 at 9 (Byrne)

Lusti Direct, Exh. 437 at 21
Lusti Surrebuttal, Exh. 442 at 9

38. Withdrawal of the Hollydale Transmission Project (2014)

Resolved between the Company and the Department. No other party provided testimony on the issue.

The Company noted in discovery that it no longer anticipates the planned capital additions to the Hollydale project and proposed to remove the associated capital costs from the rate base. In Rebuttal, the Company confirmed withdrawal of the Hollydale project and proposed to exclude it from the 2014 test year. The Department supported the Company's recommended adjustment.

Adjustment: $43,000 reduction in revenue requirements and $388,000 reduction in rate base.

Record Citations:
Clark Rebuttal, Exh. 100 at 25-26
Heuer Rebuttal, Exh. 90 at 11-12
Lusti Direct, Exh. 437 at 19-20, 27
Lusti Surrebuttal, Exh. 442 at 7-8

39. Prairie Island EPU/LCM Split Correction (2014)

Resolved between NSP and the Department. No other party provided testimony on this issue.

The Company noted that a transactional assessment of the Prairie Island EPU/LCM project costs to EPU proportion and LCM proportion was completed just prior to filing this rate case. This assessment resulted in additional project costs being assigned to the EPU part of the project. The Company made an adjustment to the interim revenue requirement but did not have time to reflect this change in the test year revenue requirement. In Rebuttal, the Company proposed to remove $2.157 million from the LCM part and add this amount to the EPU part. The Department agreed on the proposed correction.

Adjustment: $158,000 reduction in revenue requirements; $1.418 million reduction in rate base.

Record Citations:
Heuer Rebuttal, Exh. 90 at 8-9, 15
Lusti Direct, Exh. 437 at 18-19, 26-27
Lusti Surrebuttal, Exh. 442 at 2-3

40. Xcel Energy Foundation Administration Cost Correction (2014)

Resolved between NSP and the Department. No other party provided testimony on this issue.

The Company noticed in discovery that it had not removed non-labor related Foundation Administration O&M costs from the test year, and agreed to provide this adjustment in Rebuttal

Testimony. In Rebuttal, the Company proposed to remove an additional $114,622 for Foundation Administration costs from the test year. The Department supported this adjustment.

Adjustment: $114,622 reduction in revenue requirements.

Record Citations:
Heuer Direct, Exh. 88 at 10
Byrne Direct, Exh. 423 at 6-7, 48
Byrne Surrebuttal, Exh. 427 at 3-4
Lusti Surrebuttal, Exh. 442 at 31

41. Big Stone Brookings Cost Correction (2014)

The Company noted that subsequent to preparing the capital budget, a forecasted update was made to a component of the Big Stone Brookings transmission project, with an effect of lowering operating costs. The Company made an adjustment to the interim revenue requirement but did not have time to reflect this change in the test year revenue requirement. In Rebuttal, the Company proposed a corresponding adjustment to the test year. In Surrebuttal, the Department agreed on the adjustment.

Adjustment: $145,000 reduction in revenue requirements; $299,000 increase in rate base.

Record Citations:
Heuer Rebuttal, Exh. 90 at 40
Lusti Surrebuttal, Exh. 442 at 12-13

42. Bargaining Unit Wage Increase Correction (2014)

The Company noted that the 2014 test year included a 3.0 percent wage increase for bargaining unit employees. The union ratified a new agreement with a 2.6 percent wage increase after the filing of this rate case. In Rebuttal, the Company proposed a corresponding adjustment to the test year. In Surrebuttal, the Department agreed on the adjustment.

Adjustment: $405,000 reduction in revenue requirements.

Record Citations:
Heuer Rebuttal, Exh. 90 at 41
Lusti Surrebuttal, Exh. 442 at 33

43. Theoretical Reserve for Intangible Plant Correction (2014)

In its initial filing, the Company amortized all of the surplus theoretical reserve for intangible plant accounts over eight years, although the surplus reserve should have been amortized over the average remaining lives of the accounts. In Rebuttal, the Company proposed a corresponding adjustment to the test year. In Surrebuttal, the Department agreed on the adjustment.

Adjustment: $28,000 increase in revenue requirements; $77,000 reduction in rate base.

Record Citations:
Heuer Rebuttal, Exh. 90 at 41-42
Lusti Surrebuttal, Exh. 442 at 13

44. Net Operating Loss Correction (2014)

In its initial filing, the Company's net operating loss calculation in the CCOSS had an error in the calculation of deferred taxes, which were overstated because state tax credits were inadvertently excluded. In Rebuttal, the Company proposed a corresponding adjustment to the test year. In Surrebuttal, the Department agreed on the adjustment.

Adjustment: $366,000 reduction in revenue requirements; $190,000 increase in rate base.

Record Citations:
Heuer Rebuttal, Exh. 90 at 442-43
Lusti Surrebuttal, Exh. 442 at 14

45. Monticello Cyber Security Correction (2014)

At the time of its initial filing, the Company assumed that the Monticello Cyber Security project's in-service date would be delayed to 2015, and made a corresponding adjustment to the interim rate revenue requirement. In Rebuttal, the Company stated that the project is in fact on schedule to go into service during the 2014 test year as originally planned, and no adjustment is necessary to the 2014 test year revenue requirement.

Record Citations:
Heuer Rebuttal, Exh. 90 at 43

46. Alliant Wholesale Billing Revenues (2014)

In Rebuttal, the Company noted that it anticipates receiving a refund from Alliant for transmission expense paid, which will also include $561,616 accounted for in 2014 Other Revenue. The Company proposed to include this revenue in the three-year historical average of Other Revenues in a future rate case.

Record Citations:
Heuer Rebuttal, Exh. 90 at 44

47. Cost of Capital Impact (2014 and 2015 Step)

The Company will incorporate the Commission's final Order regarding capital structure, cost of debt, ROE, and overall ROR and calculate the adjustment to reflect final decisions in this case.

Record Citations:
Heuer Opening Statement, Exh. 140 at 3, 8
Evidentiary Hearing Transcript, Vol. 3 at 142, 147 (Heuer)

48. Net Operating Loss Impact (2014 and 2015 Step)

The Company calculated the impacts of its revised positions on net operating loss calculations, based on the Company's post-hearing position. The Department also calculates the NOL effect resulting from its adopted positions. The Company and the Department agreed that the NOL will need to be recalculated to reflect the impact of final decisions in this case.

Record Citations:
Heuer Rebuttal, Exh. 90 at 45-46
Heuer Opening Statement, Exh. 140 at 3, 8
Evidentiary Hearing Transcript, Vol. 3 at 142, 147 (Heuer)
Lusti Surrebuttal, Exh. 442 at 14

49. Cash Working Capital Impact (2014 and 2015 Step)

The Company calculated the CWC adjustment for 2014 and 2015 based on the Company's post-hearing position. The Department also calculates the CWC adjustment resulting from adoption of its positions. The Company and the Department agreed that CWC will need to be recalculated as part of the final compliance filing based on the revenue requirement approved in this case.

Record Citations:
Heuer Rebuttal, Exh. 90 at 46
Heuer Opening Statement, Exh. 140 at 3, 8
Evidentiary Hearing Transcript, Vol. 3 at 142, 147 (Heuer)
Lusti Direct, Exh. 437 at 24-25
Lusti Surrebuttal, Exh. 442 at 15, 42

49A. Interest Synchronization Methodology and Calculation (2014 and 2015 Step)

Formatted: Font: Bold

The Company and Department agreed on the methodology and that final interest synchronization calculation will occur after the Commission determines all cost of debt, rate base and income statement adjustments in this proceeding. As to the calculation results, for the 2014 test year and the 2015 Step, after all decisions are made, the Company and Department will calculate the 2015 Step Interest Synchronization, and no decision is needed by the ALJ on the result of the calculation.

Record Citations:
Lusti Direct, Exh. 437 at 43-44
Lusti Surrebuttal, Exh. 442 at 34

PART 2 – DEPARTMENT RATE DESIGN ISSUES

A. Disputed Department Issues – Rate Design

50. Decoupling Mechanism

Disputed among NSP, the Department, OAG, ECC, CEI, ICI Group, Commercial Group, and AARP. No other party provided testimony on this issue.

NSP Position: the Company proposed to implement a partial Revenue Decoupling Mechanism (RDM) for its Residential and Commercial Non-Demand customers. The Company accepted three recommendations by the Department: 1) implement RDM as a three-year pilot program; 2) disallow RDM surcharges in the year after the Company fails to achieve energy savings equal to 1.2 percent of retail sales; and 3) include in the annual RDM evaluation plan a comparison of how revenues under traditional regulation would have differed from those collected under partial and full decoupling.

- Partial vs. Full Decoupling: the Company recommended partial decoupling, which removes the effect of weather from monthly deferrals, because it is consistent with the Company's gradual approach to decoupling. Exclusion of weather effects does not affect RDM's main goal of removing the Company's disincentive to promote conservation. The Company believed that the Department and OAG based their conclusions to recommend full decoupling on a particular period of time that had unusual weather patterns. Simulations from other time periods showed that partial decoupling produced refunds to customers in several years. The Company stated it would evaluate at the conclusion of the pilot program whether a change to full decoupling will be appropriate.

- Cap on RDM Surcharges: the Company proposed a soft cap (deferral amounts in excess of the cap are carried over in the deferral account for recovery in subsequent years) of five percent of base revenue, excluding fuel and all applicable riders, as modified in Rebuttal. In case the Commission will order the Company to implement a full decoupling mechanism, the Company proposed a soft cap of 10 percent of base revenue, excluding fuel and all applicable riders. The Company stated that a hard cap would not fully resolve the issue of disincentive to promote energy efficiency, and hard caps are rarely used in electric decoupling mechanisms. In addition, about half of the industry decoupling mechanisms do not use a cap at all and the Company's proposed five percent cap is lower than the typical industry cap level of 10 percent.

- Applicable Customer Groups: the Company believed it would be inappropriate to expand RDM to C&I Demand class, as suggested by the OAG. The Company limited its RDM proposal to Residential and Commercial Non-Demand customers because this is consistent with the gradual approach and because for these classes the energy efficiency disincentive is the largest. Also the implementation of the decoupling mechanism is the most straightforward for these customer classes.

- Calculation of RDM Refunds and Surcharges: the Company recommended that decoupling adjustments be calculated as a dollar per kWh basis. An adjustment as a percentage of the total bill, in absence of IBR, would harm low-use customers.

- Excluding Service Outages from RDM Deferrals: the Company stated that the amount of revenue at stake is so low that that the cost of complicating the RDM design and the uncertainty in estimating lost sales outweigh any benefits of excluding service outages from RDM deferrals, as proposed by AARP.

- Theoretical Concerns: the Company did not believe that the theoretical concerns raised by other Parties were warranted. The Company stated that evaluation results do not show any widespread customer confusion because of RDM and also concerns about cross-subsidies are unwarranted because RDM calculates separate RDM deferrals and rate changes separately for each customer group. The Company expected it to become increasingly difficult to meet its energy efficiency goals due to changing market circumstances, such as stricter efficiency goals and standards and decreasing relative value of efficiency.

Department position: the Department made several recommendations to modify the Company's proposed RDM, and the Company accepted three of them as discussed above.

- Partial vs. Full Decoupling: the Department analyzed the hypothetical results if an RDM had been in place from 2009 to 2013 and from 2004 to 2013. Based on these analyses, the Department concluded that the proposed partial RDM would have an adverse impact on the Company's residential ratepayers and should not be approved. The Department noted that partial decoupling has the potential to significantly increase ratepayer costs and full decoupling could have similar effects, but to a much smaller extent. The Department recommended adopting a full decoupling mechanism as a three-year pilot program. If the Commission will not approve the full decoupling mechanism, the Department recommended maintaining current rate regulation with no RDM.

- Cap on RDM Surcharges: the Department recommended a hard cap of no greater than three percent of total revenue, including fuel and all applicable riders, to help mitigate the adverse impact of the full decoupling mechanism on ratepayers. The Department emphasized that a soft cap is not a real cap since it only changes the timing of the surcharge, but not its dollar amount. Also, the Department did not believe that a hard cap would reduce the Company's interest to maximize energy savings, because the DSM incentive mechanism is so strong.

- Applicable Customer Groups: the Department agreed with the Company's proposal and recommended that the Commission not extend decoupling to additional customer classes at this time.

- Energy Achievement Threshold: the Department recommended that the Company not be allowed to surcharge customers in any year after the Company fails to achieve energy savings equal to 1.2 percent of retail sales.

Formatted: List Paragraph, No bullets or numbering

OAG position: the OAG opposed RDM because it does not provide the Company an incentive nor does it have measureable benefits. The OAG also asserted RDM can cause customer confusion with additional line items on bills and complex deferral structure of surcharges. In addition, the OAG noted that the Company has been able to meet its energy efficiency goals in the past without any decoupling mechanism. Based on an analysis of Company data from 2009 to 2013, the OAG concluded that a full decoupling mechanism would have cost ratepayers far less than a partial decoupling mechanism. The OAG also questioned why RDM was not extended to the C&I Demand class. If the Commission will adopt a decoupling mechanism, the OAG agreed with the recommendations made by the Department, but advised the Commission to consider a lower hard cap at one to two percent. The OAG also recommended that if RDM is adopted, the customer charge should remain at its current level or to be decreased.

ECC position: ECC recommended that if RDM is approved by the Commission, the Company's request to increase customer charge should be rejected and the Company should be required to implement additional conservation programs, including the low-income renter program proposed by ECC. ECC believed that low-use, low-income households will be adversely affected by the Company's RDM and proposed that the decoupling adjustments be calculated as a percentage of the total bill basis rather than the Company-proposed dollar per kWh basis to align with the IBR proposal.

CEI position: CEI supported the Company's RDM proposal and stated that it represents a carefully tailored and wholly appropriate response to guidance from the legislature and the Commission. CEI noted that the Company's proposal is in the mainstream of utility decoupling mechanisms and designed to minimize rate volatility. CEI opposed full decoupling and a hard cap on surcharges. However, if RDM is approved by the Commission, CEI recommended that the Company's request to increase customer charge for the Residential class should be rejected. In order to align the IBR and RDM proposals, CEI also recommended that the decoupling adjustments be calculated as a percentage of the total bill basis rather than the Company-proposed dollar per kWh basis.

ICI Group position: ICI Group recommended that the Company's RDM proposal should be rejected. ICI Group was concerned that RDM would be extended in the future to larger commercial and industrial demand customers. ICI Group also believed that RDM, as proposed by the Company, would recover lost revenues, including costs never incurred by the utility.

Commercial Group position: Commercial Group agreed that if the Commission approves RDM, it should exclude Commercial Demand customers as proposed by the Company.

AARP position: AARP recommended that the Commission reject the Company's RDM proposal. AARP noted that there is little evidence of positive relationship between decoupling and energy efficiency. AARP believed the Company's RDM proposal would unfairly shift risk from the Company to consumers, particularly low-use customers who are less able to benefit from DSM efforts, and RDM would also create cross-subsidies among customer classes. If the Commission will accept RDM, AARP recommended several protections for customers, including Company commitment to provide cost-effective DSM programs, a cap of not more than two percent on annual surcharges, and exclusion of service outages from RDM deferrals. In addition, AARP agreed with the OAG recommendations related to pilot program, hard cap, and full decoupling.

Record Citations:
Sparby Direct, Exh. 25 at 3, 30-31
Sparby Rebuttal, Exh. 26 at 13-14
Hansen Direct, Exh. 109 at 2-20
Hansen Rebuttal, Exh. 110 at 1-23
Hansen Surrebuttal, Exh. 111 at 1-18
Evidentiary Hearing Transcript, Vol. 3 at 94-110 (Hansen)
Sundin Rebuttal, Exh. 42 at 3-6
Evidentiary Hearing Transcript, Vol. 1 at 141, 145-147, 152-161, 165 (Sundin)
Davis Direct, Exh. 417 at 7-14, 17-40
Davis Rebuttal, Exh. 418 at 2-8
Davis Surrebuttal, Exh. 419 at 1-17

Davis Opening Statement, Exh. 447 at 1-2
Evidentiary Hearing Transcript, Vol. 4 at 135-145 (Davis)
Nelson Direct, Exh. 375 at 53-61
Nelson Rebuttal, Exh. 377 at 38-39
Nelson Opening Statement, Exh. 142 at 1
Evidentiary Hearing Transcript, Vol. 3 at 224, 274-276 (Nelson)
Colton Direct, Exh. 234 at 27-35
Cavanagh Direct, Exh. 290 at 1-13
Cavanagh Rebuttal, Exh. 294 at 1-10
Cavanagh Opening Statement, Exh. 300 at 1
Evidentiary Hearing Transcript, Vol. 3 at 60-89 (Cavanagh)
Chernick Direct, Exh. 280 at 29-30
Glahn Direct, Exh. 250 at 12-15
Glahn Surrebuttal, Exh. 251 at 3-4
Chriss Direct, Exh. 225 at 14-15
Brockway Direct, Exh. 310 at 4-23
Brockway Rebuttal, Exh. 311 at 1-22
Brockway Surrebuttal, Exh. 312 at 1-5, 8-9

51. CCOSS

Disputed among NSP, the Department, OAG, MCC, and XLI. CEI also provided testimony related to one part of the CCOSS.

The Company, Department, OAG, MCC and XLI each present separate CCOSSs. The table below summarizes the primary positions taken by each party on disputed CCOSS elements in this case.

CCOSS Sub-Issues

Issue	NSP	Department	OAG	MCC	XLI
Classification of Fixed Production Plant	Plant Stratification	Plant Stratification	Plant Stratification	Straight Fixed-Variable (Peak Demand)	Modified Plant Stratification (Net Depreciated Replacement Value)
Allocation of Economic Development Discounts	Allocate using TY 2014 Present Revenues	Classify 100% energy, allocate based on kWh sales	Classify 100% energy, allocate based on kWh sales	Allocate using TY 2014 Base Revenues	Allocate using TY 2014 Present Revenues
Allocation of Interruptible Rate Discounts	Allocate to all customers	Allocate to all customers			Do not allocate to interruptible customers
Allocation of Other Production O&M	Predominant Nature Method	Location Method, (or overall investment method used in 12-961)	Location Method	Predominant Nature Method	Predominant Nature Method

Issue	NSP	Department	OAG	MCC	XLI
Nobles and Grand Meadow Wind Generation	Classify 100% capacity (or Percent of Base Revenue)	Plant Stratification, (or classify 100% energy)	Classify 100% energy~~, (or Plant Stratification)~~	Percent of Base Revenue, (or classify 100% capacity)	Classify 100% capacity
Pleasant Valley and Borders Wind	Plant Stratification	Plant Stratification	~~Classify 100% Energy, or~~ Plant Stratification	Rider Recovery~~Plant Stratification~~	
Split to Demand vs. Customer Distribution Costs	Minimum Distribution System (MDS) Method; Minimum Systems Study, assumptions are sound		MDS and the Study are flawed, over-estimating customer costs; allocate 10% less as customer cost		
D10S Capacity Allocator	Calculate based on NSP system peak		NSP system peak that is coincident with MISO peak	Calculate based on NSP system peak	Calculate based on NSP system peak
Plant Stratification Method – Update Cost Data		Assuming that the Company's use of updated information in Rebuttal Testimony is appropriate, u~~U~~se plant-specific data for Pleasant Valley and Borders w~~W~~ind projects~~;~~ and use 2013 cost data for all production plant costs in the application of equivalent peaker method			

The OAG also recommended that the Commission order the Company in its next rate case to thoroughly discuss how PPAs are integrated into the Company's resource planning, to conduct a zero-intercept study, and to update the Minimum Systems Study using current data and clearly document the study methodology. The Company agreed to reexamine all the assumptions supporting its Minimum Systems Study and to conduct a zero-intercept study if all the necessary data can be compiled.

Record Citations:
Peppin Direct, Exh. 102 at 3-30
Peppin Rebuttal, Exh. 103 at 2-41
Peppin Surrebuttal, Exh. 104 at 1-9
Evidentiary Hearing Transcript, Vol. 2 at 149-156 (Peppin)
Foss Direct, Exh. 69 at 1-9

Ouanes Direct, Exh. 408 at 18-44
Ouanes Rebuttal, Exh. 412 1-13
Ouanes Surrebuttal, Exh. 414 at 2-16
Ouanes Opening Statement, Exh. 445 at 1-4
Evidentiary Hearing Transcript, Vol. 4 at 58-128 (Ouanes)
Davis Direct, Exh. 417 at 5-7
Nelson Direct, Exh. 375 at 2-33
Nelson Rebuttal, Exh. 377 at 2-19
Nelson Surrebuttal, Exh. 378 at 2-17
Nelson Opening Statement, Exh. 142 at 1
Evidentiary Hearing Transcript, Vol. 3 at 226-229, 231-265, 277-289 (Nelson)
Maini Direct, Exh. 343 at 14-30
Maini Surrebuttal, Exh. 345 at 10-19
Evidentiary Hearing Transcript, Vol. 4 at 17-18, 23-29 (Maini)
Pollock Direct, Exh. 260 at 33-36
Pollock Rebuttal, Exh. 262 at 2-23
Pollock Surrebuttal, Exh. 263 at 24-29
Pollock Opening Statement, Exh. 264 at 2-3
Evidentiary Hearing Transcript, Vol. 3 at 31-34, 42-43, 45-49, 50-53 (Pollock)

52. Amount of Interruptible Service Discounts and Demand Charges

Disputed among NSP, the Department, MCC and XLI. No other party provided testimony on this issue.

NSP position: the Company proposed to increase the interruptible service discounts by 6 percent for the Performance Factor C service category, with corresponding increases for other Performance Factors that result in an overall increase of 5.1 percent for all service categories. The Company sets the discounts based on market-based approach to attract an optimal supply of interruptible load. The Company believed its proposed interruption discount for the Short Notice option at $5.85/kW per month is appropriate, considering the flexibility to quickly respond to system capacity requirements and incremental value to Short Notice customers. The proposed discounts balance the principles of moderation and longer-term resource planning needs.

Department position: the Department recognized that interruptible customers have seen rates increase in the recent years without a corresponding increase in the interruptible discount. The Department recommended a more moderate 3 percent increase to the Company's interruptible discount rates as measured at the Performance Factor C level. Under the Company's market based approach, the Company sets its interruptible rates at a level the Company believes will attract an optimal supply of interruptible load. The Company stated that it does not expect that increasing the discount rate will result in a material increase in its interruptible load.

MCC position: in order to maintain and expand the interruptible load, MCC recommended that the Tier 1 Performance Factor C credit be increased from the current $60.60/kW per year to $77.24/kW per year. MCC pointed out that interruptible credits and firm demand charges do not have comparable increases and the number of Company customers receiving interruptible service and interruptible load has been decreasing. If the Commission does not approve the MCC proposal, any other accepted recommendation should be grossed up by an additional 6.1 percent to reflect the avoidance of the planning reserve margin requirements.

XLI position: XLI stated that no increase is appropriate for the controllable demand charge for the Short Notice option and recommended the interruption discount for the Short Notice option be increased to at least $6.76/kW per month. XLI noted that the Company is proposing to increase the demand charge for Short Notice option by 19 percent but to increase the interruptible credit for Short Notice option only by 5 percent.

Record Citations:
Huso Direct, Exh. 105 at 26-28
Huso Rebuttal, Exh. 107 at 34-38
Evidentiary Hearing Transcript, Vol. 2 at 166-172, 181-185 (Huso)
Peirce Direct, Exh. 420 at 24-26, SLP-9
Peirce Surrebuttal, Exh. 422 at 14
Evidentiary Hearing Transcript, Vol. 4 at 200-203 (Peirce)
Schedin Direct, Exh. 340 at 23-24
Schedin Surrebuttal, Exh. 342 at 13
Maini Direct, Exh. 343 at 34-41
Maini Surrebuttal, Exh. 345 at 21-26
Maini Opening Statement, Exh. 145 at 1
Evidentiary Hearing Transcript, Vol. 4 at 12 (Maini)
Pollock Direct, Exh. 260 at 48-55
Pollock Surrebuttal, Exh. 263 at 35-38
Pollock Opening Statement, Exh. 264 at 3-4
Evidentiary Hearing Transcript, Vol. 3 at 34 (Pollock)

53. Revenue Apportionment

Disputed among NSP, the Department, OAG, MCC, XLI, and the Commercial Group.

NSP position: the Company proposed to move the Residential class 75 percent closer to cost; set the C&I Non-Demand apportionment at the cost-based level; maintain the current level of Lightning class revenues; and recover the remaining revenue requirement from the C&I-Demand class. The Company proposed an updated revenue apportionment for 2014 and 2015, presented in witness Huso's Rebuttal Testimony, Table 3 and Table 4. In Rebuttal, the Company revised the C&I Non-Demand class to 75 percent movement to cost. The Company and the Department agreed on the proportional adjustment mechanism to adjust the revenue apportionment to reflect the Commission's final Order in this case.

Department position: the Department's proposed, updated revenue apportionment for 2014 and 2015 was presented in witness Peirce's Surrebuttal Testimony, Table 3 and Table 4. The proposal moved all classes closer to cost while moderating the overall rate increases to all classes. The Department relied on the CCOSS recommendations of witness Dr. Ouanes to develop its initial apportionment of revenue responsibility. The Department updated its apportionment by proportionally adjusting the revised revenue requirement to reflect its apportionment recommendations in Direct Testimony. The proportional adjustment methodology is consistent with the methodology approved by the Commission in the Company's prior to rate cases.

OAG position: the OAG stated that CCOSS is an imprecise model with no measurement for error, and therefore it should not be used as an absolute metric for rates, and also non-cost factors should be considered in rate design. The OAG's proposed revenue apportionment for 2014 and 2015 was presented in witness Nelson's Direct Testimony, Table 9 and Table 10.

MCC position: MCC recommended that the revenue allocation follow the cost of service. MCC opposed the revenue apportionment recommendations made by the Department and the OAG. MCC did not oppose using the Company's CCOSS to establish the revenue apportionment, so long as the CCOSS was modified to include percent of base revenue approach for the classification of Nobles and Grand Meadow Wind generation.

XLI position: XLI believed that CCOSS should be the primary factor in determining revenue apportionment and it is important to set rates to class cost in order to promote equity, efficiency, conservation, and stability. XLI also noted that the subsidy provided by C&I Demand customers should be eliminated. XLI made revenue apportionment recommendations based on the Company's CCOSS (as modified by XLI) and presented them in witness Pollock's Direct Testimony, Schedule 10.

Commercial Group position: the Commercial Group did not oppose the Company's proposed revenue allocation, based on the Company's proposed CCOSS. The Commission should, at the minimum, maintain the Company's proposed movement towards cost of service, and additionally determine to what extent rates can be moved closer to cost of service for each class.

Record Citations:
Huso Direct, Exh. 105 at 7-13
Huso Rebuttal, Exh. 107 at 1-9
Peirce Direct, Exh. 420 at 5-10
Peirce Surrebuttal, Exh. 422 at 1-4
Peirce Opening Statement, Exh. 448 at 1
Evidentiary Hearing Transcript, Vol. 4 at 148-150 (Peirce)
Nelson Direct, Exh. 375 at 33-40
Nelson Rebuttal, Exh. 377 at 21
Nelson Surrebuttal, Exh. 378 at 17-18
Maini Direct, Exh. 343 at 30-34
Maini Surrebuttal, Exh. 345 at 19-21
Pollock Direct, Exh. 260 at 37-47
Pollock Rebuttal, Exh. 262 at 24-29
Pollock Surrebuttal, Exh. 263 at 30-32
Pollock Opening Statement, Exh. 264 at 3
Evidentiary Hearing Transcript, Vol. 3 at 34 (Pollock)
Chriss Direct, Exh. 225 at 4-5, 13-14

54. Residential and Small General Service Customer Charges

Disputed among NSP, the Department, OAG, ECC, CEI, and AARP. No other party provided testimony on this issue.

NSP position: the Company proposed a $1.25 increase in customer charges for each Residential service category and a $1.50 increase for the Small General Service customers, as presented in Table 8 in witness Huso's Direct Testimony. The Company believed its proposed customer charges appropriately balance several factors, including the cost of service, moderation, intra-class equity, and conservation. The Company believed its recommendation is also consistent with the Commission's most recent decisions regarding customer charges.

Department position: because the Company recently raised customer charges, and to reflect the customer charges set in recent other electric utility rate cases, the Department recommended a more modest increase of $.50 for each Residential service category and for the Small General Service customers. The Department stated that low income customers exist across all usage levels, and a balanced approach to rate design is therefore necessary and reasonable.

OAG position: the OAG opposed any increases in customer charges for several reasons: multiple recent increases in the customer charge, relatively high percentage increase proposed, disproportionate impact on low-use residential customers, and effect as disincentive to conserve energy. The OAG also recommended that if the Commission orders a decoupling mechanism, then the customer charges should remain at the current level or be decreased.

ECC position: ECC believed that the increased customer charge proposed by the Company will have substantial adverse effects on low-income customers and their ability to participate in energy efficiency programs, and therefore it should be rejected. ECC also believed that the Company's data and calculations have methodological and data errors and the Company's discussion on the impact of customer charges on LIHEAP customers is unreliable. In addition, ECC stated that the concern that a lower customer charge will harm low-income, high-use customers is unwarranted.

CEI position: CEI recommended that the residential customer charges should not be increased. CEI believed that the Department used the Company's overstated customer costs as a basis to determine appropriate customer charges and the Department's concern about intra-class subsidiaries is unwarranted. Decoupling is another reason not to increase customer charges.

AARP position: AARP recommended that the residential customer charges should remain at their current levels. The increased customer charges proposed by the Company will place undue burdens on low-use residential customers and reduce the incentive to conserve energy for higher-use customers. The extraordinary situation of some extremely high-use residential customers should not determine customer charge policy for the vast majority of residential customers.

Record Citations:
Huso Direct, Exh. 105 at 14-20
Huso Rebuttal, Exh. 107 at 24-33
Huso Surrebuttal, Exh. 108 at 7-9
Peirce Direct, Exh. 420 at 12-13

Peirce Surrebuttal, Exh. 422 at 6-12
Peirce Opening Statement, Exh. 448 at 1
Evidentiary Hearing Transcript, Vol. 4 at 148, 150-165, 183-196, 204-220 (Peirce)
Nelson Direct, Exh. 375 at 40-52, 59
Nelson Rebuttal, Exh. 377 at 22-23
Nelson Surrebuttal, Exh. 378 at 21-23
Colton Direct, Exh. 234 at 29, 35-41
Colton Rebuttal, Exh. 237 at 1-14
Colton Opening Statement, Exh. 242 at 1-2
Evidentiary Hearing Transcript, Vol. 3 at 12-15 (Colton)
Marshall Rebuttal, Exh. 238 at 1-6
Chernick Direct, Exh. 280 at 3, 26-29
Chernick Rebuttal, Exh. 293 at 1-16
Chernick Opening Statement, Exh. 299 at 1
Evidentiary Hearing Transcript, Vol. 3 at 54-55 (Chernick)
Cavanagh Direct, Exh. 290 at 8-9
Cavanagh Opening Statement, Exh. 300 at 1
Evidentiary Hearing Transcript, Vol. 3 at 76 (Cavanagh)
Brockway Direct, Exh. 310 at 24-33
Brockway Surrebuttal, Exh. 312 at 10-11

55. Low-Income Discount Program

~~Disputed between~~Resolved among NSP, the Department, and ECC. No other party provided testimony on this issue.

NSP position: the Company disagreed with the Department's recommendation to expand the low-income discount program's eligibility, because it would require an alternative administrative process with Company validation of eligibility, because of compliance concerns with the current statutory framework for the low-income discount program, and because there is sufficient federal funding available for all LIHEAP eligible customers.

Department position: in light of the IBR Stipulation, the Department no longer supports its original position and is in agreement with NSP and ECC regarding expansion of the low-income discount program.~~the Department recommended that the Company's low-income discount program should be expanded and made available to all ratepayers who qualify for LIHEAP assistance, regardless whether they are actually receiving LIHEAP assistance.~~

ECC position: ECC disagreed with the Department recommendation because the Minnesota law governing the low-income discount rider requires that participants receive LIHEAP and because the program administration would be expensive and burdensome.

Record Citations:
Gersack Surrebuttal, Exh. 74 at 10-12
Grant Rebuttal, Exh. 416 at 6
Marshall Surrebuttal, Exh. 240 at 8-9

B. Resolved Department Issues – Rate Design

56. CCR – Amount of Economic Development Discounts

Resolved among NSP, the Department, and OAG. No other party provided testimony on this issue.

The Department recommended that the 2014 and 2015 Competitive Response Rider (CRR) economic development discounts to be recovered in base rates should be reduced (halved) ~~set equal~~ to the level of actual 2013 economic development discounts. In Rebuttal, the Company agreed on this proposal for this case. Also the OAG supported the Department's recommendation.

Record Citations:
Huso Rebuttal, Exh. 107 at 38-39
Ouanes Direct, Exh. 408 at 41-44
Ouanes Surrebuttal, Exh. 414 at 11-12
Nelson Rebuttal, Exh. 377 at 19

57. FCA Rider/Base Cost of Energy – Nuclear Disposal Fees (2014)

Resolved between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company explained that the spent nuclear fuel disposal fee is included in the 2014 test year as a component of the cost of fuel as well as fuel revenue (making it cost neutral), therefore the test year revenue deficiency is not materially affected by the removal of the disposal fee from the test year. The Company recommended that the base cost of energy be adjusted to reflect the removal of the disposal fee in compliance at the conclusion of this case.

Department position: the Department noted that the Company collects the DOE spent nuclear disposal fees through the FCA, and the Company received notification from the DOE that the disposal fee was reduced to zero effective May 16, 2014. The Department recommended that the base cost of energy amount ($0.02780 per kWh) and the class-specific base costs of energy amounts be reduced accordingly. The Department-recommended base cost of energy was $0.02748 per kWh.

Record Citations:
Heuer Rebuttal, Exh. 90 at 13-14
Ouanes Direct, Exh. 408 at 14-18

58. CIP Rider: CCRC and CAF

Resolved between NSP and the Department. No other party provided testimony on this issue.

The Company proposed to zero out and remove Conservation Cost Recovery Charge (CCRC) from base rates and recover all CIP program costs through the CIP Adjustment Factor (CAF). The Department supported the Company's proposal. The Company agreed that the CCRC be zeroed out when final rates are implemented. Also, the Company agreed to submit an updated Conservation Cost Recovery Adjustment (CCRA) filing 90 days before final rates are estimated to go into effect.

Record Citations:
Heuer Rebuttal, Exh. 90 at 10-11
Peppin Direct, Exh. 102 at 32-33
Peppin Rebuttal, Exh. 103 at 42
Evidentiary Hearing Transcript, Vol. 2 at 157-159 (Peppin)
Davis Direct, Exh. 417 at 3-7
Lusti Surrebuttal, Exh. 442 at 34

59. Windsource Rider

Resolved between NSP and the Department. No other party provided testimony on this issue.

NSP position: the Company accepted the Department's recommendation to identify and justify changes to historical data in future Windsource and FCA filings and to use consistent terminology in these filings.

Department position: the Department was concerned that the Company has changed historical data in the Windsource tracker reports without providing any justification, explanation, or even simply identifying such changes. The Department recommended that the Commission require the Company not to change historical data without identifying such changes and providing a justification for such changes in Windsource and FCA filings. The Department also had concerns about using confusing terminology in the Windsource and FCA reports and recommended that the Company should clarify in each FCA and Windsource filing what costs are included in the Windsource Contract Payments.

Record Citations:
Peppin Direct, Exh. 102 at 31-32
Peppin Rebuttal, Exh. 103 at 42-43
Ouanes Direct, Exh. 408 at 6-13

60. Time-of-Day Energy Charges/Energy Charge Credit

Resolved between NSP and the Department. No other party provided testimony on this issue.

The Department recommended the Commission approve the Company's proposed TOD Energy Charge methodology and the proposed increase in the energy charge credit.

Record Citations:
Huso Direct, Exh. 105 at 21-25
Peirce Direct, Exh. 420 at 22-24

61. Firm Service Demand Charges

Resolved. No party other than the Company provided testimony on this issue.

The Company proposed to increase firm service demand charges.

Record Citations:
Huso Direct, Exh. 105 at 25-26.

62. Voltage Discount

Resolved. No party other than the Company provided testimony on this issue.

The Company proposed to increase the demand charge discounts for the Transmission voltage level.

Record Citations:
Huso Direct, Exh. 105 at 28.

62A. Base Energy Charges for the C&I Demand Class

Resolved between NSP and the Department. No other party provided testimony on this issue.

The Department accepted the rates proposed by the Company, as they appear consistent with the results of the modified CCOSS recommended by the Department; the Department also recommended approval of the Company's proposed energy rates.

Record Citations:
Peirce Direct, Exh. 420 at 22

Formatted: Font: Bold

PART 3 – OTHER OAG ISSUES

63. CWIP/AFUDC

Disputed among NSP, OAG, and Commercial Group. No other party provided testimony on this issue.

NSP position: the Company disagreed with the recommendations offered by the OAG and Commercial Group and continued to request accounting for CWIP and AFUDC according to long-standing Commission practice. The Company noted that neither FERC nor Minnesota rules allow accumulation of AFDUC when projects are placed in CWIP without an AFUDC offset, and when everything is held constant, FERC and Minnesota methods produce the same results. The AFUDC offset assures that the asset being constructed accumulates the true cost of financing during construction, not the current rate of return. Without AFUDC, shareholders would be providing construction financing through very substantial amounts of invested and reinvested equity at no cost. Internally generated funds should receive a return as internally generated funds are available for distribution for to shareholders. The Company has calculated and applied the AFUDC rate consistent with FERC accounting requirements and also correctly accounted for AFUDC on cancelled or suspended projects. The Company stated that if CWIP and AFUDC were removed from ratemaking for projects that are less than $25 million, the Company would be denied recovery of any cost of capital associated with financing approximately $441 million in CWIP investment in the test year (approximately 60 percent of all CWIP investment).

OAG position: the OAG believed that the Company's accounting for CWIP and AFUDC violates FERC requirements, specifically, because FERC limits CWIP to 50 percent in rate base, allows either CWIP in rate base or AFUDC but not both, and disallows AFUDC during project interruptions. The OAG also noted that the purpose of AFUDC is to recognize the need for external funding, yet the Company accrues AFUDC on virtually all CWIP projects despite the fact that it has substantial internal funding available and all projects do not require external financing. The OAG also believed that the Company has continued to accrue AFUDC during project interruptions and delays. The OAG recommended 1) excluding all CWIP from rate base and removing AFUDC from the income statement, 2) allowing AFUDC only on CWIP projects that cost over $25 million, 3) disallowing AFUDC on CWIP projects that are delayed or interrupted during the period of interruption, and 4) removing equity from AFUDC rate calculation and setting the AFUDC rate at 2.62 percent, which reflects a weighted cost of short-term and long-term debt.

Commercial Group position: the Commercial Group recommended removing CWIP from rate base, because the inclusion of CWIP charges ratepayers for assets during construction that are not yet used and useful. The Commercial Group also noted that CWIP shifts to ratepayers risks that are traditionally assumed by utility investors, and if a project is delayed or not completed, ratepayers have no resource for recovering what they have paid for CWIP in rates.

Disputed amount: $3.8 million reduction in revenue requirements for the 2014 test year and $0.9 million increase in revenue requirements for the 2015 Step (OAG Recommendation).

Record Citations:
Perkett Direct, Exh. 92 at 51-63
Perkett Rebuttal, Exh. 94 at 14-38
Perkett Opening Statement, Exh. 130 at 2-3
Evidentiary Hearing Transcript, Vol. 2 at 58 (Perkett)
Tyson Rebuttal, Exh. 31 at 11-15
Guest Direct, Exh. 91 at 2-11
Lindell Direct, Exh. 370 at 16-29
Lindell Surrebuttal, Exh. 373 at 1-17
Evidentiary Hearing Transcript, Vol. 3 at 196-216, 221-222 (Lindell)
Chriss Direct, Exh. 225 at 10-11

64. Nuclear Refueling Outage Costs – Accounting Methodology

Disputed between NSP and OAG. No other party provided testimony on this issue.

NSP position: the Company proposed to continue to use the deferral and amortization methodology that it has used since 2008, because the methodology moderates the rate increase and variation effects and matches the outage costs to the period when benefits are provided. The Company also requested a carrying charge equal to the rate of return for the unamortized amount of nuclear refueling outage costs. The Company stated that this is a standard ratemaking practice and consistent with past rate cases; the carrying charge simply represents the time value of money until the full amount of expense is recovered, typically over 18 to 24 months.

OAG position: the OAG believed that earning a return on a normal expense is inappropriate and provides an incentive for the Company to increase the scope of nuclear refueling outage costs. The OAG continued to believe that the normalization method to set rates is superior, but recommended that the Company could be allowed to use the deferral and amortization methodology to set rates. However, the OAG suggested that the Company not be allowed to earn any return on nuclear refueling outage costs.

Disputed amount: $4.6 million adjustment and reduction in revenue requirements.

Record Citations:
Robinson Direct, Exh. 95 at 21
Robinson Rebuttal, Exh. 97 at 21-25
Robinson Opening Statement, Exh. 132 at 2
Evidentiary Hearing Transcript, Vol. 2 at 97, 101-105 (Robinson)
Lindell Direct, Exh. 370 at 44-47
Lindell Surrebuttal, Exh. 373 at 24

65. Corporate Aviation Costs (2014)

Disputed between NSP and OAG. No other party provided testimony on this issue.

NSP position: the Company requested recovery of 50 percent of its test year aviation costs ($954,425), accordingly to the Commission's established practice. The Company believed that this adjustment already takes into account many of the concerns raised by the OAG, and any further adjustments are unnecessary. The Company noted that its corporate aviation services provide several generally recognized benefits, and disallowance based on a "vague business reason" analysis of the Company's flight logs is inappropriate.

OAG position: the OAG raised three main concerns regarding the Company's corporate aviation costs: the Company's cost per flight was excessive; many of the flights scheduled did not provide ratepayer benefits; and most of the flights recorded did not include a sufficient business purpose to determine whether the flight was necessary and prudent to provide utility service. Based on these reasons and a review of the Company's flight logs, the OAG recommended disallowing the majority of the corporate aviation costs and allowing recovery of $34,143.

Disputed amount: $920,282 adjustment and reduction in revenue requirements.

Record Citations:
O'Hara Direct, Exh. 75 at 28-32
O'Hara Rebuttal, Exh. 77 at 1-12
O'Hara Opening Statement, Exh. 124 at 1-2
Evidentiary Hearing Transcript, Vol. 1 at 250-251, 253-257 (O'Hara)
Lindell Direct, Exh. 370 at 47-58

66. Interest Rate on Interim Rate Refund

Disputed between NSP and OAG. No other party provided testimony on this issue.

NSP position: the Company disagreed with the OAG recommendation and stated that the interest rate on interim rate refund should not be increased above the Prime Rate. The Company explained that the revenues from the interim rates are considered equivalent to short-term debt for the Company, and the Company's short term borrowing rate is lower than the Prime Rate (0.62 percent vs. 3.25 percent). This means that applying the Prime Rate to refund amounts is a net added cost to the Company because it is higher than the rate Company would pay on other short-term financing. In addition, the refund amount includes any excess expenses (plus any excess return on the rate base determined at the Company's overall rate of return), which means that the OAG recommendation would pay overall rate of return on expenses despite the fact that the Company does not earn a return on expenses.

OAG position: the OAG pointed out that in the Company's last rate case, the Commission determined that the Prime Rate applied to interim rate refunds was inequitable for ratepayers and instead the Company's full weighted cost of capital (i.e., the Company's overall rate of return) should be used as the interest rate for refunds. The OAG recommended that the Company's full weighted cost of capital should be used as the interest rate on interim rate refund also in this case.

Record Citations:
Clark Direct, Exh. 99 at 26
Heuer Rebuttal, Exh. 90 at 37-39
Tyson Rebuttal, Exh. 31 at 23-24
Lindell Direct, Exh. 370 at 58-59
Evidentiary Hearing Transcript, Vol. 3 at 217-221 (Lindell)
Evidentiary Hearing Transcript, Vol. 5 at 78-82, 87-89 (Lusti)

PART 4 – OTHER MCC ISSUES

67. Fuel Cost Recovery Reform

Disputed among NSP, MCC, and XLI. Also the Department provided testimony on this issue.

NSP position: the Company noted that concerns regarding the current process for fuel cost recovery have been raised by other stakeholders in the AAA Docket (Docket No. E999/AA-12-757). Since these issues are not unique to the Company, it believed that the AAA Docket is the best forum to continue the discussions to ensure that all interested Parties have a chance to participate. The Company also believed that it is important to work toward an incentive-based plan that is reasonably within the Company's control.

Department position: the Department acknowledged that designing incentive mechanisms for fuel costs is important and should be done in the near future. Because the issue involves also other investor-owned utilities, the Department believed it would be best addressed in the AAA Docket.

MCC position: MCC stated that the Company's current FCA Rider allows recovery of fuel costs as they occur and shifts burden of proof to consumers to prove after the fact that any costs were imprudent. MCC also noted that although fuel cost recovery has been discussed in the AAA Docket, no action has been taken so far. MCC supported extensive reform of fuel cost recovery, and at a minimum, believed that automatic recovery of replacement fuel costs due to planned or forced outages should not be allowed. MCC recommended that if there is no resolution on this issue in the AAA Docket by the time the Company submits its next rate case, the Company should be ordered to provide a new FCA structure.

XLI position: XLI noted that the annual review of the prudency of the costs recovered through the FCA Rider does not protect customers' interests and places little or no risk of disallowance to the Company. XLI recommended that NSP should be ordered to develop a FCA Rider that places stronger incentives for ensuring that the costs flowing through are prudent and reasonable. Since the discussions in the AAA Docket have not produced results, XLI recommended that the new FCA design should be presented in the Company's next rate case or within 90 days of the Commission's final order in this case, whichever is earlier.

Record Citations:
Clark Rebuttal, Exh. 100 at 42-43
Evidentiary Hearing Transcript, Vol. 2 at 124-127, 134-135 (Clark)
Robinson Rebuttal, Exh. 97 at 25
Ouanes Rebuttal, Exh. 412 at 11-15
Maini Direct, Exh. 343 at 41-43
Maini Surrebuttal, Exh. 345 at 26-27
Pollock Direct, Exh. 260 at 25-32
Pollock Surrebuttal, Exh. 263 at 33-34
Pollock Opening Statement, Exh. 264 at 2
Evidentiary Hearing Transcript, Vol. 3 at 30-31, 49-50, 52 (Pollock)

68. Sherco Unit 3 Outage – Replacement Fuel Costs

Disputed between NSP and MCC. Also the Department provided testimony on this issue.

NSP position: the Company believed that the replacement fuel costs during the Sherco 3 outage would be best addressed in the AAA Docket, because the issue pertains to fuel cost recovery and because these costs were not included in this rate case. In addition, the Company disagreed on capitalizing these costs, because the cost of replacement power should be covered by those customers who used the power during the outage rather than future customers.

Department position: the Department agreed with the Company that the issue of Sherco 3 replacement power costs should be addressed in the AAA Docket.

MCC position: MCC believed that the replacement fuel costs during Sherco 3 outage should be addressed in this case and capitalized over the remaining life of the facility; a corresponding adjustment could be made in the annual FCA filing. Extraordinary replacement energy costs should be paid by ratepayers who benefit from the project over its life.

Record Citations:
Clark Rebuttal, Exh. 100 at 44
Robinson Rebuttal, Exh. 97 at 25
Perkett Rebuttal, Exh. 94 at 47, 54-55
Anderson Rebuttal, Exh. 37 at 4

Lusti Direct, Exh. 437 at 67-68
Schedin Direct, Exh. 340 at 13-15
Schedin Surrebuttal, Exh. 342 at 9
Evidentiary Hearing Transcript, Vol. 3 at 172 (Schedin)

69. Transmission Business Area – Cost Controls

Disputed between NSP and MCC. No other party provided testimony on this issue.

NSP position: the Company disagreed with MCC recommendations and stated that the Transmission organization already has rigorous cost control mechanisms in place. In addition, the Company's use of a +/- 30-percent cost estimate at the certificate of need stage is appropriate for transmission projects, given the level of uncertainty at this stage of the permitting process when the final route for a transmission line has not been determined. For the same reason, a firm cost cap for transmission projects at the certificate of need level would be unreasonable and inappropriate. The Company believed that the MCC recommendation for additional cost controls at the MISO level is inconsistent with recently approved MISO tariff language as well as the FERC's determination that the MISO cost review process is just and reasonable.

MCC position: MCC raised concerns about the Transmission Business Area costs and perceived lack of cost controls. MCC recommended that the Company should create a KPI mechanism to address accountability, directly in the responsibility area of the Vice President of Transmission, for example, including a requirement that each transmission project requiring a certificate of need should have a firm cost cap, which cannot be exceeded for ratemaking purposes without Commission approval. ~~and that the Company and MISO transmission owners should set up cost control mechanisms at MISO for projects that do not require a certificate of need.~~

Record Citations:
Kline Rebuttal, Exh. 67 at 2-37
Schedin Direct, Exh. 340 at 15-21
Schedin Surrebuttal, Exh. 342 at 9-11

70. FERC Cost Comparison Study – KPI Benchmarks

Disputed between NSP, the Department, and MCC. No other party provided testimony on this issue.

NSP position: the Company disagreed with the MCC recommendation and stated that it already has implemented appropriate and sufficient KPIs to manage non-fuel O&M growth. The target for 2014 is to limit recoverable O&M growth to no more than 2.2 percent. In addition, the Company noted that the 2013 Electric FERC Comparison Study is a simplistic analysis, and does not control for the comparability of data, different tracking and reporting systems, relative size of the utility's transmission system, or other similar variations among utilities. Therefore, the Company believed it is inappropriate to use non-fuel and transmission O&M benchmarks from the Comparison Study as KPIs.

Department position: the Department agreed with MCC's recommendation to use benchmarks from the Comparison Study to improve the efficiency of the Company's operations.

MCC position: based on the Company's 2013 Electric FERC Comparison Study, MCC noted that the Company is trending below its peer companies with respect to non-fuel O&M and transmission O&M costs. MCC recommended that the Company should use non-fuel and transmission O&M cost benchmarks from the Comparison Study as KPIs (for those benchmarks that are not in the first or second quartile in the Study) to help improve the efficiency of operations.

Record Citations:
Clark Rebuttal, Exh. 100 at 44-47
Kline Rebuttal, Exh. 67 at 37-45
Ouanes Rebuttal, Exh. 412 at 16
Maini Direct, Exh. 343 at 43-45
Maini Surrebuttal, Exh. 345 at 27-28

71. Coincident Peak Billing

Disputed between NSP and MCC. No other party provided testimony on this issue.

NSP position: the Company disagreed with the MCC's proposal because it would require additional billing processes, would only impact nine customers, and is not consistent with established rate design.

MCC position: MCC recommended that the Company should be required to adopt a coincident peak billing option for customers with demands of 500 kW or more and aggregate all demand interval readings to determine and bill the diversified peak demand.

Record Citations:
Huso Rebuttal, Exh. 107 at 42-44
Evidentiary Hearing Transcript, Vol. 2 at 186-189 (Huso)
Schedin Direct, Exh. 340 at 24-26
Schedin Surrebuttal, Exh. 342 at 13-15
Evidentiary Hearing Transcript, Vol. 3 at 172-175, 187 (Schedin)

72. Definition of Contiguous in Rate Book

Disputed between NSP and MCC. No other party provided testimony on this issue.

NSP position: the Company noted the statutory definition of contiguous property is applicable for only meter aggregations used with net metering, as described in Minn. Stat. 216B.164. No definition is necessary for coincident peak billing, and the Company has provided a definition for other applications as part of discovery.

MCC position: MCC proposed the Company should adopt the new definition of contiguous property, as defined in the new solar law.

Record Citations:
Huso Rebuttal, Exh. 107 at 42-44
Schedin Direct, Exh. 340 at 24
Schedin Surrebuttal, Exh. 342 at 14-15
Exh. 136 (Company Response to MCC-251)

73. Standby Service Tariff – Manner of Service

Resolved between NSP and MCC. No other party provided testimony on this issue.

NSP position: the Company agreed that MCC's recommendations related to standby service tariff should be reviewed in the separate Docket No. E002/M-13-315. The Company did indicate it disagreed with the positions offered by MCC.

MCC position: MCC requested that its testimony regarding standby rates be included in Docket No. E002/M-13-315. MCC recommended that the Company is required to provide true firm standby service by reserving a block of standby capacity from its own resources to serve all of its standby customers as a group, or otherwise the Company should bear the responsibility for certifying the customers' generators with MISO.

Record Citations:
Huso Rebuttal, Exh. 107 at 40-42
Schedin Direct, Exh. 340 at 26-30
Schedin Surrebuttal, Exh. 342 at 15-16

74. DG Tariff Change

Resolved between NSP and MCC. No other party provided testimony on this issue.

NSP position: the Company noted that it was under the impression that it had agreed with MCC to work through the advisory group Rulemaking to incorporate the DG tariff change. The Company agreed to file the DG tariff change as a miscellaneous filing in July 2014.

MCC position: MCC stated that under the 2010 rate case Stipulation and Settlement Agreement, NSP was required to submit a DG tariff change which would place a cap on DG interconnection study fees. In October 2013, NSP and MCC agreed on the terms of the DG tariff change, but the Company has not yet filed the change. In Surrebuttal, MCC acknowledged that the Company was going to make a miscellaneous tariff filing to address the DG Tariff.

Record Citations:
Huso Rebuttal, Exh. 107 at 40
Schedin Direct, Exh. 340 at 22-23
Schedin Surrebuttal, Exh. 342 at 12-13

PART 5 – OTHER XLI ISSUES

75. Nuclear Theoretical Depreciation Reserve (2014)

Disputed among NSP, the Department, OAG, and XLI. No other party provided testimony on this issue.

NSP position: the Company opposed the XLI recommendation and stated that the Company's methodology for calculating the nuclear theoretical depreciation reserve is accurate, reasonable, and very similar to theoretical reserve computations by vintage, because it computes a reserve ratio for each account group. The Company also noted that every dollar of accumulated depreciation that is used to lower the revenue requirement over the next five years will need to be paid back over the remaining life, and XLI's proposal would increase revenue requirements in year six by $47.2 million. The Company offered as an alternative to employ regulatory accounting to depreciate the nuclear units over a remaining life that is longer than the license life, extending the useful life 5-10 years beyond the operating license period.

Department position: the Department did not agree with~~support~~ XLI's recommendation because the Department did not support the use of supposed surplus theoretical depreciation reserves to provide a short-term reduction in rates, in part because ratepayers would have to repay this depreciation expense and pay a return on higher rate base as well. In addition, the Department noted that theoretically depreciation reserve give back is not consistent with past depreciation decisions and IRP decisions. Finally, the Department noted that there is no reasonable basis to conclude that ratepayers have overpaid for nuclear depreciation or that there is a "surplus" theoretical reserve. ~~it is unreasonable, short-sighted, and would result in higher rates for ratepayers in the long run. Also, the Department did not believe that there is a surplus in the nuclear depreciation reserve.~~

OAG position: the OAG opposed the XLI recommendation because it is unreasonable and fails to properly analyze the impact on ratepayers in the future.

XLI position: XLI believed the Company's analysis is flawed and severely understates the magnitude of the depreciation reserve surplus that it has accumulated in the nuclear production plant account. The Company's analysis has two main problems: future interim plant additions were included in determining remaining life values, and theoretical reserve amounts were calculated by account total, not by individual asset vintages. XLI stated that the updated amount of accumulated surplus is approximately $208 million (Minnesota Jurisdiction), which is $136 million more than the Company originally estimated. XLI recommended that the Company be required to amortize the nuclear depreciation reserve surplus of $208 million over five years.

Disputed amount: $25.7 million reduction in revenue requirements assuming a five-year amortization.

Record Citations:
Clark Rebuttal, Exh. 100 at 38-39
Perkett Direct, Exh. 92 at 43-51
Perkett Rebuttal, Exh. 94 at 7-14, 55
Perkett Opening Statement, Exh. 130 at 2
Evidentiary Hearing Transcript, Vol. 2 at 57, 66-71, 76-77 (Perkett)
Campbell Rebuttal, Exh. 434 at 2-4, 7

Campbell Opening Statement, Exh. 450 at 11
Lindell Opening Statement, Exh. 141 at 1
Evidentiary Hearing Transcript, Vol. 3 at 190-192 (Lindell)
Pollock Direct, Exh. 260 at 9-19
Pollock Surrebuttal, Exh. 263 at 8-19
Pollock Opening Statement, Exh. 264 at 1-2
Evidentiary Hearing Transcript, Vol. 3 at 28-29, 44-45 (Pollock)
Colton Opening Statement, Exh. 242 at 1-3

76. Black Dog – Unit 2 and 5 Outage Costs (2014)

Disputed between NSP and XLI. No other party provided testimony on this issue.

NSP position: the Company agreed that the FCA proceeding is the appropriate place to address XLI's concerns over the replacement power costs for Black Dog Unit 2 and 5 outages. However, XLI is also seeking disallowance of costs that were incurred outside the 2014 test year and not included in this rate case. The Company stated it would be inconsistent with the principle of test year to disallow these costs. Despite the Company's best efforts, it is not possible to completely eliminate human errors, and the Company believed a human error should not be an automatic reason to disallow costs.

XLI position: XLI noted that the Black Dog Unit 2 outage (also affecting Unit 5) that occurred from December 2012 to March 2013 was the result of a human error. Therefore, XLI recommended that all capital investment and any operating expenses associated with the repair of the unit should be disallowed. Also, XLI suggested that the replacement fuel costs associated with this outage should be disallowed in the next annual FCA proceeding.

Disputed amount: $ 1.838 million reduction in revenue requirements and $24,104 reduction in rate base.

Record Citations:
Clark Direct, Exh. 99 at 44
Heuer Rebuttal, Exh. 90 at 35
Mills Direct, Exh. 58 at 54
Mills Rebuttal, Exh. 60 at 15-19
Evidentiary Hearing Transcript, Vol. 2 at 14-16 (Mills)
Pollock Direct, Exh. 260 at 23-24
Pollock Opening Statement, Exh. 264 at 2
Evidentiary Hearing Transcript, Vol. 3 at 230, 40-41 (Pollock)

77. Renewable Energy Purchase Tariff (Renew-a-Source)

Disputed between NSP and XLI. No other party provided testimony on this issue.

NSP position: the Company confirmed its commitment to begin discussions with XLI and other interested stakeholders on developing a program that addresses XLI interests, however, the

Company recommended against a particular deadline for commencing discussions or making a specific tariff proposal.

XLI position: XLI recommended that in order to match around-the-clock high load customers with renewable energy resources, the Company should develop a specific tariff under which the Company can purchase and sell renewable energy directly to qualifying high load factor customers. The Company would have the leverage of negotiating better prices and matching the output of defined portfolio of renewable resources with the customers' load shapes. XLI recommended that the Commission order the Company to work with interested Parties and develop such a new tariff, to be filed no later than the Company's next rate case. XLI also proposed guidelines for the tariff and recommended that discussions on the tariff should commence within 60 days after the final Order is issued in this case.

Record Citations:
Clark Rebuttal, Exh. 100 at 47-48
Evidentiary Hearing Transcript, Vol. 2 at 131-135 (Clark)
Pollock Direct, Exh. 260 at 59-62
Pollock Surrebuttal, Exh. 263 at 42-43
Pollock Opening Statement, Exh. 264 at 4-6
Evidentiary Hearing Transcript, Vol. 3 at 35-37 (Pollock)

78. Time of Use Rates – Definition of On-Peak Period

Disputed between NSP and XLI. No other party provided testimony on this issue.

NSP position: the Company disagreed with the XLI proposal. The proposal is based on the system seasonal peak capacity differential, which is accurately recognized in the seasonal demand change differential and does not relate to energy and fuel cost charges.

XLI position: XLI recommended that the peak period be limited to summer months only, consistent with the Company's predominant summer capacity peak and the change to summer peak allocator in the CCOSS. XLI believed that customers should be provided an opportunity to actually respond to price signals through meaningful and sustained changes in their usage patterns, which is currently difficult based on a 12-hour peak period on all weekdays throughout the year.

Record Citations:
Huso Rebuttal, Exh. 107 at 44-45
Evidentiary Hearing Transcript, Vol. 2 at 172-175 (Huso)
Pollock Direct, Exh. 260 at 56-58
Pollock Surrebuttal, Exh. 263 at 39-42
Pollock Opening Statement, Exh. 264 at 4
Evidentiary Hearing Transcript, Vol. 3 at 35 (Pollock)

PART 6 – OTHER ICI GROUP ISSUES

79. Rate Shock

ICI Group position: the ICI Group opposed the additional rate increases as sought by the Company because the cumulative effect of five rate increases over the past ten years will cause "rate shock." The ICI Group also pointed out that the Company intends to file another general rate case seeking another rate increase in 2015. The result of such consistent and onerous rate increases will be to decrease the competitiveness of Minnesota businesses that compete in regional, national, and international markets. The consistent rate increases also lead to rates that are not "just and reasonable" as required by Minnesota Statutes.

Record Citations:
Glahn Direct, Exh. 250 at 3-5
Glahn Opening Statement, Exh. 254
Clark Direct, Exh. 99 at 10-13
Sparby Direct, Exh. 25 at 45

79A. MYRP in General

Disputed between NSP and ICI Group. No other party recommended not allowing MYRP.

NSP position: the Company recommended that the Commission accept the MYRP as proposed and modified by the Company during this proceeding. The Company proposed a multi-year rate plan as the best regulatory fit to reflect the current environment of significant investments. MYRP offers several benefits: greater rate predictability for customers, opportunities for rate moderation, regulatory efficiency, and long-term view of Company financials. The Company noted that MYRP provides additional benefits for customers, because the 2015 Step does not reflect the Company's full revenue requirement for 2015. The Company believed that MYRP will also provide benefits into 2016, as long as it is implemented in a manner that balances the interests of all Company stakeholders.

ICI Group position: the ICI Group opposed the Company's MYRP proposal for several reasons: the 2015 Step will get less scrutiny and lower-level review than a regular one-year rate case; the 2015 Step will move the Company from regulatory lag to regulatory lead and may allow the Company to over-earn if the U.S. economy improves; the inclusion of only Company-selected items in the 2015 Step tilts the playing field against customers who will not have access to the Company's entire 2015 financial data; and the process and reporting requirements for setting the 2015 Step rates are extremely complicated. The ICI Group believed that even with the risk of annual, consecutive rate cases, customers benefit from the transparency of having all revenue and expenses examined at one time in one proceeding. The ICI Group recommended that the Company's MYRP will be denied and the rates set in this proceeding based on 2014 test year costs and assets.

Record Citations:
Sparby Direct, Exh. 25 at 16-18
Sparby Rebuttal, Exh. 26 at 10-12
Clark Direct, Exh. 99 at 6-10

Formatted: Font: Not Bold

Clark Rebuttal, Exh. 100 at 2, 4-8
Heuer Direct, Exh. 88 at 6-7
Glahn Direct, Exh. 250 at 6-9
Glahn Surrebuttal, Exh. 251 at 1-2

PART 7 – OTHER CEI ISSUES

80. Inclining Block Rate (IBR)

Resolved among NSP, CEI, ECC and the Department. Also OAG and AARP provided testimony on this issue.

NSP, CEI, ECC, and the Suburban Rate Authority entered into a Stipulation Agreement on Inclining Block Rates during the Evidentiary Hearing. The Parties to the Stipulation requested that the Commission open a new docket and require the Company to file a proposal for an IBR rate structure, in a form of compliance filing, 120 days after the Commission issues its final order in this proceeding. All the evidence and arguments regarding the IBR from this case will be incorporated into the new docket.

Department position: the Department agreed that the IBR structure can be considered and implemented outside of a general rate case and noted that it no longer supported a requirement related to parallel billing for study purposes or to develop customer education means in this case. The Department also agreed to convene stakeholder meetings and review the Company's IBR proposal, as stated in the Stipulation Agreement, if the Commission so orders.

OAG position: the OAG noted that IBR programs can cause significant and detrimental unintended consequences, as demonstrated by CenterPoint Energy's IBR that was first suspended and then cancelled after further investigation. The OAG did not believe that the IBR proposed by CEI provides enough detail to ensure that it would not unfairly impact certain groups of customers. If the Commission chooses to move forward and consider an IBR, it would be appropriate to consider IBR in another proceeding, where multiple rate design proposals can be fully presented, analyzed, and compared. The OAG declined to enter into the Stipulation Agreement at this time.

AARP position: AARP did not recommend that the Commission approve inclining block rates in this docket.

Record Citations:
Sparby Rebuttal, Exh. 26 at 9-10
Clark Surrebuttal, Exh. 101 at 2-3, 7-8
Clark Opening Statement, Exh. 134 at 1
Evidentiary Hearing Transcript, Vol. 2 at 1115-117, 127-131, 138-143 (Clark)
Huso Rebuttal, Exh. 107 at 10-24
Huso Surrebuttal, Exh. 108 at 2-6
Grant Rebuttal, Exh. 416 at 1-6
Grant Opening Statement, Exh. 446 at 1-2
Evidentiary Hearing Transcript, Vol. 4 at 129-132 (Grant)
Nelson Rebuttal, Exh. 377 at 23-38

Nelson Surrebuttal, Exh. 378 at 20-21
Evidentiary Hearing Transcript, Vol. 3 at 266, 275-276 (Nelson)
Chernick Direct, Exh. 280 at 3-26
Chernick Surrebuttal, Exh. 295 1-14
Nissen Surrebuttal, Exh. 298 at 1-5
Chernick Opening Statement, Exh. 299 at 1-3
Evidentiary Hearing Transcript, Vol. 3 at 55-56, 57-58 (Chernick)
Colton Direct, Exh. 234 at 4-27
Colton Surrebuttal, Exh. 239 at 1-25
Colton Opening Statement, Exh. 242 at 1-3
Evidentiary Hearing Transcript, Vol. 3 at 12-16 (Colton)
Marshall Surrebuttal, Exh. 240 at 7-8, 10-11
Brockway Direct, Exh. 310 at 23
Stipulation on Inclining Block Rates, Exh. 135 at 1-7
Evidentiary Hearing Transcript, Vol. 2 at 115-117, 144-147

PART 8 – OTHER ECC ISSUES

81. Low-Income Renter Conservation Program

Resolved among NSP, ECC, the Department, and OAG. No other party provided testimony on this issue.

ECC position: ECC recommended that the Company should implement a low-income conservation program for renters who live in smaller housing units. There is substantial need and opportunity for promoting energy efficiency in low-income, one- to four-unit rental dwellings, and low-income renters are unable to invest in energy efficiency measures without financial assistance. In Surrebuttal, ECC agreed that the standard CIP process is appropriate for developing and implementing the low-income renter conservation program.

NSP position: the Company noted that it currently offers CIP programs that are also available for low-income renters in smaller housing units through Home Energy Savings Program (HESP) and Multi-Family Energy Savings Program (MESP). The Company is also currently evaluating and redefining its conservation programs and design options for the multi-family segment in the CIP process. The Company explained that this evaluation will also include addressing the need for program modifications or new programs for one- to four-unit rental properties. The Company agreed to modify its CIP plan once the new program is fully developed.
Department position: to the extent that the Company's current programs are available to low-income renters, they should be evaluated and utilized first before creating a new program. If a need is found to develop an additional CIP program for low-income renters who live in smaller housing units, the Department recommended ordering the Company to work with the Department CIP staff to develop such a program.

OAG position: the OAG agreed that low-income renters are one of the groups at most risk being negatively impacted by IBR and would also provide the largest marginal efficiency gains with respect to conservation investment. However, the ECC proposal lacks details and specificity (e.g., what is the form of assistance).

Record Citations:
Heuer Rebuttal, Exh. 90 at 36-37
Sundin Rebuttal, Exh. 42 at 16-18
Sundin Opening Statement, Exh. 118 at 2-3
Evidentiary Hearing Transcript, Vol. 1 at 143-144, 147-151 (Sundin)
Evidentiary Hearing Transcript, Vol. 2 at 120 (Clark)
Grant Rebuttal, Exh. 416 at 7
Peirce Surrebuttal, Exh. 422 at 13
Nelson Rebuttal, Exh. 377 at 31
Marshall Direct, Exh. 235 at 1-31
Marshall Rebuttal, Exh. 238 at 6-7
Marshall Surrebuttal, Exh. 240 at 1-3

PART 9 – OTHER

Formatted: Centered

82. Reasonableness of the Company's Annual Incentive Compensation Program

The Commission's Ordering Paragraph 30 in its September 3, 2013 Findings of Fact, Conclusions, and Order in Docket No. E002/GR-12-961 directed that the Company "shall evaluate the goals set for its annual incentive program to determine if they are too lenient or if they actually require stretching to meet; the Company shall file the results of the evaluation in its next rate case." Department witness Mr. Lusti reported that, from his review of the Annual Incentive Compensation Reports for the years 2008-2012, he found that the Company's employees meet their KPI requirement goals nearly always. The Company's actual AIP compensation paid as a percentage of AIP Target for the years 2010, 2011, 2012 and 2012 was 103 percent, 94 percent, 118 percent and 120 percent, respectively. The top twenty Company employees in 2013 received, as a group, 192 percent of target level compensation. Because this is a compliance issue of the Commission, the ALJ and the Commission will need to determine if the Company's AIP is reasonable.

Record Citations:
Lusti Direct, Exh. 437 at 56-59
Lusti Direct Attachments, Exh. 438, DVL-20, Schedule 2 and DVL-37