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DEFINITIONS

As required by Minnesota Rules, Part 7825.3800, the following information shall be supplied as a part of the utility's notice of a change in rates. Information requirements Parts 7825.3900, 7825.4000, item A; 7825.4100, item A; 7825.4200, item A; and 7825.4300, items A and B, as defined herein, shall be supplied by all gas and electric utilities and all other information requirements prescribed by Parts 7825.3800 to 7825.4400 shall be supplied where applicable to the utility.

For purposes of complying with the Financial Information requirements prescribed by Parts 7825.3900, 7825.4000, 7825.4100, 7825.4200, 7825.4300, 7825.4400, and 7825.4500, the following definitions have been used by Northern States Power Company (Minnesota) in this filing:

Most Recent Fiscal Year

This information represents actual financial information for the calendar year ended December 31, 2018.

Projected Fiscal Year

The projected fiscal year is the fiscal year immediately following the most recent fiscal year (2018). For the purposes of this filing, this information represents actual and projected financial information for the calendar year ending December 31, 2019. 2020 unadjusted test year data has also been provided as a projected period in support of this filing.

Proposed Test Year and Plan Years

The proposed test year information represents the budgets developed for the 2020 calendar year. The 2021 and 2022 plan years are developed using the 2020 proposed test year plus adjustments based on the capital budgets developed for the 2021 and 2022 calendar years in addition to budget and projected costs for other components of the cost of service. The proposed test year 2020 and proposed plan years 2021 and 2022 include the effects of ratemaking adjustments.

DEFINITIONS (Continued)

Five Year Forecast

The five year forecast information is provided for comparison purpose and represents the budgets developed for the 2020 through 2024 calendar years. In addition, all five years of the forecast include the effects of ratemaking adjustments.

Unadjusted Financial Information

Unadjusted financial information consists of financial data before ratemaking adjustments.

Adjusted Financial Information

Adjusted financial information consists of financial data prepared with ratemaking adjustments included.

Note on Rounding:

The cost of service study on which these supporting schedules are based rounds numbers to the nearest thousand for display purposes. However, the subtotals and subsequent totals in the cost of service study are based on actual values resulting in occasional differences in the totals displayed and the sum of the line items. These supporting schedules were prepared using individual line items with subtotals and totals calculated on each schedule. This results in occasional differences between the subtotals and totals on the cost of service study and those on supporting schedules.

JURISDICTIONAL FINANCIAL SUMMARY SCHEDULES
(PART 7825.3900)

A jurisdictional financial summary schedule as required by parts 7825.3800 and 7825.3900 shall be filed showing:

A. the proposed rate base, operating income, overall rate of return, and the calculation of income requirements, income deficiency, and revenue requirements for the test year;

B. the actual unadjusted average rate base consisting of the same components as the proposed rate base, unadjusted operating income, overall rate of return, and the calculation of income requirements, income deficiency, and revenue requirements for the most recent fiscal year; and

C. the projected unadjusted average rate base consisting of the same components as the proposed rate base, unadjusted operating income under present rates, overall rate of return, and the calculation of income requirements, income deficiency, and revenue requirements for the projected fiscal year.

Northern States Power Company
Electric Utility - State of Minnesota
JURISDICTIONAL FINANCIAL SUMMARY SCHEDULES
($000's)

Docket No. E002/GR-19-564
Financial Information
Schedule A-1

Line No.	Description	Adjusted (1) Most Recent Fiscal Year 2018 (A)	Adjusted (1) Projected Fiscal Year 2019 (B)	Adjusted (1) Proposed Test Year 2020 (C)	Adjusted (1) Plan Year 2021 (D)	Adjusted (1) Plan Year 2022 (E)
1	Average Rate Base	$8,268,371	$8,673,282	$8,986,901	$9,309,544	$9,805,740
2	Operating Income	$479,123	$618,148	$497,145	$414,729	$366,852
3	Allowance for funds used during construction	$29,731	$24,842	$28,846	$31,000	$33,500
4	Total Available for Return	$508,854	$642,990	$525,991	$445,729	$400,352
5	Overall Rate of Return (Line 4 / Line 1)	6.15%	7.41%	5.85%	4.79%	4.08%
6	Required Rate of Return	7.53%	7.47%	7.45%	7.45%	7.47%
7	Required Operating Income (Line 1 x Line 6)	$622,608	$647,894	$669,524	$693,561	$732,489
8	Income Deficiency (Line 7 - Line 4)	$113,754	$4,904	$143,533	$247,832	$332,137
9	Gross Revenue Conversion Factor	1.403351	1.403351	1.403351	1.403351	1.403351
10	Revenue Deficiency (Line 8 x Line 9)	$159,637	$6,883	$201,427	$347,795	$466,104
11	Retail Related Revenues Under Present Rates	$3,088,783	$3,265,140	$3,121,140	$3,080,944	$3,069,438
12	Percentage Increase Needed in Overall Revenue (Line 10 / Line 11)	5.17%	0.21%	6.45%	11.29%	15.19%

(1) Revenues and expenses for riders have been included where applicable.

Northern States Power Company
Electric Utility - State of Minnesota
JURISDICTIONAL FINANCIAL SUMMARY SCHEDULES
($000's)

Docket No. E002/GR-19-564
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Schedule A-2

Line No.	Description	Unadjusted (1) Most Recent Fiscal Year 2018 (A)	Unadjusted (1) Projected Fiscal Year 2019 (B)	Unadjusted (1) Proposed Test Year 2020 (C)	Unadjusted (1) Plan Year 2021 (D)	Unadjusted (1) Plan Year 2022 (E)
1	Average Rate Base	$8,247,385	$9,017,617	$10,067,382	$10,812,048	$11,277,585
2	Operating Income	$512,103	$626,661	$578,077	$528,979	$480,406
3	Allowance for funds used during construction	$29,731	$25,603	$28,853	$31,116	$33,511
4	Total Available for Return	$541,834	$652,264	$606,930	$560,095	$513,917
5	Overall Rate of Return (Line 4 / Line 1)	6.57%	7.23%	6.03%	5.18%	4.56%
6	Required Rate of Return	7.09%	7.08%	7.08%	7.08%	7.08%
7	Required Operating Income (Line 1 x Line 6)	$584,740	$638,447	$712,771	$765,493	$798,453
8	Income Deficiency (Line 7 - Line 4)	$42,906	($13,817)	$105,840	$205,398	$284,536
9	Gross Revenue Conversion Factor	1.403351	1.403351	1.403351	1.403351	1.403351
10	Revenue Deficiency (Line 8 x Line 9)	$60,212	($19,390)	$148,531	$288,246	$399,304
11	Retail Related Revenues Under Present Rates	$3,093,514	$3,273,073	$3,198,144	$3,184,046	$3,166,345
12	Percentage Increase Needed in Overall Revenue (Line 10 / Line 11)	1.95%	-0.59%	4.64%	9.05%	12.61%

(1) Revenues and expenses for riders have been included where applicable.

RATE BASE SCHEDULES
(PART 7825.4000)

The following rate base schedules as required by parts 7825.3800 and 7825.4000 shall be filed:

A. A rate base summary schedule by major rate base component (e.g. plant in service, construction work in progress, and plant held for future use) showing the proposed rate base, the unadjusted average rate base for the most recent fiscal year and unadjusted average rate base for the projected fiscal year. The totals for this schedule shall agree with the rate base amounts included in the financial summary.

B. A comparison of total utility and Minnesota jurisdictional rate base amounts by detailed rate base component showing:

   1) total utility and the proposed jurisdictional rate base amounts for the test year including the adjustments, if any, used in determining the proposed rate base:
   2) the unadjusted average total utility and jurisdictional rate base amounts for the most recent fiscal year and the projected fiscal year.

C. Adjustment schedules, if any, showing the title, purpose, and description and the summary calculations of each adjustment used in determining the proposed jurisdictional rate base.

D. A summary by rate base component of the assumptions made and the approaches used in determining average unadjusted rate base for the projected fiscal year. Such assumptions and approaches shall be identified and quantified into two categories: known changes from the most recent fiscal year and projected changes.

E. For multi-jurisdictional utilities only, a summary by rate base component of the jurisdictional allocation factors used in allocating the total utility rate base amount to the Minnesota jurisdiction. This summary shall be supported by a schedule showing for each allocation factor the total utility and jurisdictional statistics used in determining the proposed rate base and the Minnesota jurisdictional rate base for the most recent fiscal year and the projected fiscal year.

Northern States Power Company
Electric Utility - State of Minnesota
RATE BASE SCHEDULES
RATE BASE SUMMARY
($000's)

Docket No. E002/GR-19-564
Financial Information
Schedule A-1

Line No.	Description	Adjusted (1) Most Recent Fiscal Year 2018 (A)	Adjusted (1) Projected Fiscal Year 2019 (B)	Adjusted (1) Proposed Test Year 2020 (C)	Adjusted (1) Plan Year 2021 (D)	Adjusted (1) Plan Year 2022 (E)
1	Utility Plant in Service	$18,063,903	$18,962,545	$19,958,469	$20,817,953	$21,700,191
2	Less: Reserve for Depreciation	$8,117,836	$8,638,215	$9,295,420	$10,004,539	$10,641,880
3	Net Utility Plant in Service	$9,946,067	$10,324,331	$10,663,050	$10,813,415	$11,058,311
4	Utility Plant Held for Future Use	0	0	0	0	0
5	Construction Work in Progress	574,105	451,945	363,989	417,804	507,890
6	Less: Accumulated Deferred Income Taxe:	2,465,612	2,353,166	2,301,002	2,187,638	2,015,705
7	Cash Working Capital	(171,911)	(119,217)	(119,149)	(127,030)	(140,888)
	Other Rate Base Items					
8	Materials and Supplies	$168,024	$153,932	$153,932	$153,932	$153,932
9	Fuel Inventory	68,794	65,875	65,875	65,875	65,875
10	Non-Plant Assets & Liabilities	54,318	43,291	60,475	81,070	90,346
11	Customer Advances	72,393	69,703	(9,797)	67,952	68,129
12	Interest on Customer Deposits	(9,860)	(9,797)	(54,826)	(9,797)	(9,797)
13	Prepaids and Other	(72,959)	(54,826)	68,747	(54,826)	(54,826)
14	Regulatory Amortizations	105,013	101,211	95,608	88,788	82,473
15	Total Other Rate Base Items	$385,721	$369,389	$380,013	$392,994	$396,132
16	Total Average Rate Base	$8,268,371	$8,673,282	$8,986,901	$9,309,544	$9,805,740

(1) Revenues and expenses for riders have been included where applicable.

Northern States Power Company
Electric Utility - State of Minnesota
RATE BASE SCHEDULES
RATE BASE SUMMARY
($000's)

Docket No. E002/GR-19-564
Financial Information
Schedule A-2

Line No.	Description	Unadjusted (1) Most Recent Fiscal Year 2018 (A)	Unadjusted (1) Projected Fiscal Year 2019 (B)	Unadjusted (1) Proposed Test Year 2020 (C)	Unadjusted (1) Plan Year 2021 (D)	Unadjusted (1) Plan Year 2022 (E)
1	Utility Plant in Service	$18,063,903	$19,248,739	$20,987,865	$22,459,297	$23,496,188
2	Less: Reserve for Depreciation	$8,117,836	$8,640,889	$9,313,149	$10,064,393	$10,767,342
3	Net Utility Plant in Service	$9,946,067	$10,607,849	$11,674,717	$12,394,904	$12,728,846
4	Utility Plant Held for Future Use	0	0	0	0	0
5	Construction Work in Progress	624,621	604,068	521,530	466,594	508,517
6	Less: Accumulated Deferred Income Taxe:	2,434,475	2,328,990	2,283,455	2,214,211	2,118,982
7	Cash Working Capital	(169,536)	(133,489)	(129,815)	(139,445)	(154,456)
	Other Rate Base Items					
8	Materials and Supplies	$168,024	$153,932	$153,932	$153,932	$153,932
9	Fuel Inventory	68,794	65,875	65,875	65,875	65,875
10	Non-Plant Assets & Liabilities	54,318	43,291	60,475	81,070	90,346
11	Customer Advances	72,393	69,703	68,747	67,952	68,129
12	Interest on Customer Deposits	(9,860)	(9,797)	(9,797)	(9,797)	(9,797)
13	Prepaids and Other	(72,959)	(54,826)	(54,826)	(54,826)	(54,826)
14	Regulatory Amortizations	0	0	0	0	0
15	Total Other Rate Base Items	$280,708	$268,178	$284,405	$304,206	$313,659
16	Total Average Rate Base	$8,247,385	$9,017,617	$10,067,382	$10,812,048	$11,277,585

(1) Revenues and expenses for riders have been included where applicable.

Northern States Power Company
Electric Utility - State of Minnesota
RATE BASE SCHEDULES
DETAILED RATE BASE COMPONENTS
($000's)

Docket No. E002/GR-19-564
Financial Information
Schedule B-1

		Proposed Test Year 2020					
		Total Utility			Minnesota Jurisdiction		
Line No.	Description	Unadjusted (A)	Adjustments (B)	Adjusted (C) (A) + (B)	Unadjusted (D)	Adjustments (E)	Adjusted (F) (D) + (E)
	Electric Plant as Booked						
1	Production	$13,956,816	($1,084,037)	$12,872,778	$12,114,337	($998,895)	$11,115,442
2	Transmission	3,773,349	(12,781)	3,760,568	3,281,379	(12,781)	3,268,599
3	Distribution	4,439,012	0	4,439,012	3,883,261	0	3,883,261
4	General	1,101,039	(17,721)	1,083,317	958,608	(17,721)	940,887
5	Common	861,661	0	861,661	750,280	0	750,280
6	TOTAL Utility Plant in Service	$24,131,876	($1,114,539)	$23,017,336	$20,987,865	($1,029,396)	$19,958,469
	Reserve for Depreciation						
7	Production	$7,299,546	($18,846)	$7,280,700	$6,343,405	($16,647)	$6,326,757
8	Transmission	859,966	(10)	859,956	728,397	(10)	728,387
9	Distribution	1,632,155	0	1,632,155	1,446,041	0	1,446,041
10	General	529,865	(1,072)	528,793	461,045	(1,072)	459,973
11	Common	383,872	0	383,872	334,261	0	334,261
12	TOTAL Reserve for Depreciation	$10,705,404	($19,928)	$10,685,476	$9,313,149	($17,729)	$9,295,420
	Net Utility Plant in Service						
13	Production	$6,657,270	($1,065,191)	$5,592,079	$5,770,932	($982,248)	$4,788,685
14	Transmission	2,913,383	(12,771)	2,900,612	2,552,983	(12,771)	2,540,212
15	Distribution	2,806,857	0	2,806,857	2,437,219	0	2,437,219
16	General	571,173	(16,649)	554,525	497,562	(16,648)	480,914
17	Common	477,789	0	477,789	416,019	0	416,019
18	Net Utility Plant in Service	$13,426,471	($1,094,611)	$12,331,861	$11,674,717	($1,011,667)	$10,663,050
19	Utility Plant Held for Future Use	$0	$0	$0	$0	$0	$0
20	Construction Work in Progress	$597,512	($157,555)	$439,957	$521,530	($157,542)	$363,989
21	Less: Accumulated Deferred Income Taxes	$2,596,303	$19,561	$2,615,864	$2,283,455	$17,547	$2,301,002
22	Cash Working Capital	($145,597)	$12,391	($133,206)	($129,815)	$10,666	($119,149)
	Other Rate Base Items:						
23	Materials and Supplies	$176,908	$0	$176,908	$153,932	$0	$153,932
24	Fuel Inventory	75,984	0	75,984	65,875	0	65,875
25	Non-Plant Assets & Liabilities	72,003	0	72,003	60,475	0	60,475
26	Customer Advances	(11,777)	0	(11,777)	(9,797)	0	(9,797)
27	Interest on Customer Deposits	(54,994)	0	(54,994)	(54,826)	0	(54,826)
28	Prepaids and Other	79,092	0	79,092	68,747	0	68,747
29	Regulatory Amortizations	0	104,360	104,360	0	95,608	95,608
30	Total Other Rate Base Items	$337,216	$104,360	$441,577	$284,405	$95,608	$380,013
31	Total Average Rate Base	$11,619,300	($1,154,975)	$10,464,325	$10,067,382	($1,080,481)	$8,986,901

(1) Revenues and expenses for riders have been included where applicable.

Northern States Power Company
Electric Utility - State of Minnesota
RATE BASE SCHEDULES
DETAILED RATE BASE COMPONENTS
($000's)

Docket No. E002/GR-19-564
Financial Information
Schedule B-1 (2)

		Adjusted (1) Plan Year 2021		Adjusted (1) Plan Year 2022	
Line No.	Description	Total Utility (A)	Minnesota Jurisdiction (B)	Total Utility (C)	Minnesota Jurisdiction (D)
	Electric Plant as Booked				
1	Production	$13,380,594	$11,481,125	$13,621,180	$11,673,805
2	Transmission	3,871,783	3,359,259	4,027,285	3,490,183
3	Distribution	4,707,724	4,136,381	5,104,737	4,500,875
4	General	1,165,338	1,010,202	1,246,268	1,080,459
5	Common	954,347	830,985	1,096,625	954,870
6	TOTAL Utility Plant in Service	$24,079,786	$20,817,953	$25,096,095	$21,700,191
	Reserve for Depreciation				
7	Production	$7,800,210	$6,774,974	$8,223,319	$7,136,281
8	Transmission	928,483	787,936	998,538	848,684
9	Distribution	1,715,984	1,519,172	1,805,026	1,597,559
10	General	598,133	520,017	670,608	582,722
11	Common	462,172	402,441	547,379	476,634
12	TOTAL Reserve for Depreciation	$11,504,982	$10,004,539	$12,244,870	$10,641,880
	Net Utility Plant in Service				
13	Production	$5,580,384	$4,706,151	$5,397,861	$4,537,524
14	Transmission	2,943,300	2,571,324	3,028,747	2,641,499
15	Distribution	2,991,741	2,617,209	3,299,711	2,903,316
16	General	567,205	490,186	575,660	497,737
17	Common	492,175	428,545	549,246	478,235
18	Net Utility Plant in Service	$12,574,804	$10,813,415	$12,851,225	$11,058,311
19	Utility Plant Held for Future Use	$0	$0	$0	$0
20	Construction Work in Progress	$483,557	$417,804	$579,001	$507,890
21	Less: Accumulated Deferred Income Taxes	$2,493,929	$2,187,638	$2,310,566	$2,015,705
22	Cash Working Capital	($141,786)	($127,030)	($157,026)	($140,888)
	Other Rate Base Items:				
23	Materials and Supplies	$176,908	$153,932	$176,908	$153,932
24	Fuel Inventory	75,984	65,875	75,984	65,875
25	Non-Plant Assets & Liabilities	94,015	81,070	103,791	90,346
26	Customer Advances	(11,777)	(9,797)	(11,777)	(9,797)
27	Interest on Customer Deposits	(54,994)	(54,826)	(54,994)	(54,826)
28	Prepaids and Other	78,189	67,952	78,396	68,129
29	Regulatory Amortizations	97,114	88,788	90,371	82,473
30	Total Other Rate Base Items	$455,439	$392,994	$458,680	$396,132
31	Total Average Rate Base	$10,878,085	$9,309,544	$11,421,314	$9,805,740

(1) Revenues and expenses for riders have been included where applicable.

Northern States Power Company
Electric Utility - State of Minnesota
RATE BASE SCHEDULES
DETAILED RATE BASE COMPONENTS
($000's)

Docket No. E002/GR-19-564
Financial Information
Schedule B-1 (3)

		Adjusted (1) Most Recent Fiscal Year 2018		Adjusted (1) Projected Fiscal Year 2019	
Line No.	Description	Total Utility (A)	Minnesota Jurisdiction (B)	Total Utility (C)	Minnesota Jurisdiction (D)
	Electric Plant as Booked				
1	Production	$11,398,192	$9,972,085	$12,115,746	$10,518,283
2	Transmission	3,566,548	3,126,401	3,677,862	3,198,497
3	Distribution	4,048,140	3,543,665	4,227,333	3,695,938
4	General	944,651	827,203	1,010,473	879,629
5	Common	679,088	594,549	769,690	670,199
6	TOTAL Utility Plant in Service	$20,636,620	$18,063,903	$21,801,105	$18,962,545
	Reserve for Depreciation				
7	Production	$6,393,509	$5,600,240	$6,809,827	$5,918,162
8	Transmission	$729,774	621,253	790,211	667,737
9	Distribution	1,487,586	1,320,329	1,555,107	1,379,457
10	General	401,671	351,404	460,040	400,250
11	Common	256,562	224,610	313,068	272,609
12	TOTAL Reserve for Depreciation	$9,269,103	$8,117,836	$9,928,254	$8,638,215
	Net Utility Plant in Service				
13	Production	$5,004,683	$4,371,845	$5,305,919	$4,600,121
14	Transmission	2,836,774	2,505,149	2,887,651	2,530,761
15	Distribution	2,560,554	2,223,336	2,672,226	2,316,480
16	General	542,980	475,799	550,432	479,379
17	Common	422,526	369,939	456,622	397,590
18	Net Utility Plant in Service	$11,367,517	$9,946,067	$11,872,851	$10,324,331
19	Utility Plant Held for Future Use	$0	$0	$0	$0
20	Construction Work in Progress	$666,963	$574,105	$545,338	$451,945
21	Less: Accumulated Deferred Income Taxes	$2,804,197	$2,465,612	$2,673,507	$2,353,166
22	Cash Working Capital	($191,163)	($171,911)	($133,392)	($119,217)
	Other Rate Base Items:				
23	Materials and Supplies	$191,665	$168,024	$176,908	$153,932
24	Fuel Inventory	78,920	68,794	75,984	65,875
25	Non-Plant Assets & Liabilities	64,954	54,318	52,595	43,291
26	Customer Advances	(12,320)	(9,860)	(11,777)	(9,797)
27	Interest on Customer Deposits	(73,141)	(72,959)	(54,994)	(54,826)
28	Prepaids and Other	82,756	72,393	80,187	69,703
29	Regulatory Amortizations	114,619	105,013	110,390	101,211
30	Total Other Rate Base Items	$447,454	$385,721	$429,293	$369,389
31	Total Average Rate Base	$9,486,575	$8,268,371	$10,040,582	$8,673,282

(1) Revenues and expenses for riders have been included where applicable.

Northern States Power Company
Electric Utility - State of Minnesota
RATE BASE SCHEDULES
DETAILED RATE BASE COMPONENTS
($000's)

Docket No. E002/GR-19-564
Financial Information
Schedule B-2

Line No.	Description	Unadjusted (1) Proposed Test Year 2020 Total Utility (A)	Minnesota Jurisdiction (B)	Unadjusted (1) Plan Year 2021 Total Utility (C)	Minnesota Jurisdiction (D)	Unadjusted (1) Plan Year 2022 Total Utility (C)	Minnesota Jurisdiction (D)
	Electric Plant as Booked						
1	Production	$13,956,816	$12,114,337	$15,015,348	$13,030,270	$15,375,687	$13,342,206
2	Transmission	3,773,349	3,281,379	3,929,990	3,417,466	4,119,214	3,582,112
3	Distribution	4,439,012	3,883,261	4,707,724	4,136,381	5,104,737	4,500,875
4	General	1,101,039	958,608	1,199,331	1,044,195	1,281,935	1,116,125
5	Common	861,661	750,280	954,347	830,985	1,096,625	954,870
6	TOTAL Utility Plant in Service	$24,131,876	$20,987,865	$25,806,739	$22,459,297	$26,978,198	$23,496,188
	Reserve for Depreciation						
7	Production	$7,299,546	$6,343,405	$7,861,128	$6,830,940	$8,348,313	$7,253,560
8	Transmission	859,966	728,397	928,765	788,218	1,000,072	850,218
9	Distribution	1,632,155	1,446,041	1,715,984	1,519,172	1,805,026	1,597,559
10	General	529,865	461,045	601,739	523,622	677,257	589,371
11	Common	383,872	334,261	462,172	402,441	547,379	476,634
12	TOTAL Reserve for Depreciation	$10,705,404	$9,313,149	$11,569,787	$10,064,393	$12,378,047	$10,767,342
	Net Utility Plant in Service						
13	Production	$6,657,270	$5,770,932	$7,154,220	$6,199,330	$7,027,374	$6,088,646
14	Transmission	2,913,383	2,552,983	3,001,224	2,629,248	3,119,142	2,731,894
15	Distribution	2,806,857	2,437,219	2,991,741	2,617,209	3,299,711	2,903,316
16	General	571,173	497,563	597,592	520,573	604,678	526,754
17	Common	477,789	416,019	492,175	428,545	549,246	478,235
18	Net Utility Plant in Service	$13,426,471	$11,674,717	$14,236,952	$12,394,904	$14,600,151	$12,728,846
19	Utility Plant Held for Future Use	$0	$0	$0	$0	$0	$0
20	Construction Work in Progress	$597,512	$521,530	$532,349	$466,594	$579,629	$508,517
21	Less: Accumulated Deferred Income Taxes	$2,596,303	$2,283,455	$2,516,592	$2,214,211	$2,409,547	$2,118,982
22	Cash Working Capital	($145,597)	($129,815)	($155,996)	($139,445)	($172,502)	($154,456)
	Other Rate Base Items:						
23	Materials and Supplies	$176,908	$153,932	$176,908	$153,932	$176,908	$153,932
24	Fuel Inventory	75,984	65,875	75,984	65,875	75,984	65,875
25	Non-Plant Assets & Liabilities	72,003	60,475	94,015	81,070	103,791	90,346
26	Customer Advances	(11,777)	(9,797)	(11,777)	(9,797)	(11,777)	(9,797)
27	Interest on Customer Deposits	(54,994)	(54,826)	(54,994)	(54,826)	(54,994)	(54,826)
28	Prepaids and Other	79,092	68,747	78,189	67,952	78,396	68,129
29	Regulatory Amortizations	0	0	0	0	0	0
30	Total Other Rate Base Items	$337,216	$284,405	$358,325	$304,206	$368,309	$313,659
31	Total Average Rate Base	$11,619,300	$10,067,382	$12,455,038	$10,812,048	$12,966,039	$11,277,585

(1) Revenues and expenses for riders have been included where applicable.

Northern States Power Company
Electric Utility - State of Minnesota
RATE BASE SCHEDULES
DETAILED RATE BASE COMPONENTS
($000's)

Docket No. E002/GR-19-564
Financial Information
Schedule B-2 (2)

Line No.	Description	Unadjusted (1) Most Recent Fiscal Year 2018 Total Utility (A)	Unadjusted (1) Most Recent Fiscal Year 2018 Minnesota Jurisdiction (B)	Unadjusted (1) Projected Fiscal Year 2019 Total Utility (C)	Unadjusted (1) Projected Fiscal Year 2019 Minnesota Jurisdiction (D)
	Electric Plant as Booked				
1	Production	$11,398,192	$9,972,085	$12,443,248	$10,803,218
2	Transmission	3,566,548	3,126,401	3,678,186	3,198,821
3	Distribution	4,048,140	3,543,665	4,227,333	3,695,938
4	General	944,651	827,203	1,011,407	880,563
5	Common	679,088	594,549	769,690	670,199
6	TOTAL Utility Plant in Service	$20,636,620	$18,063,903	$22,129,864	$19,248,739
	Reserve for Depreciation				
7	Production	$6,393,509	$5,600,240	$6,812,887	$5,920,824
8	Transmission	$729,774	621,253	$790,211	667,737
9	Distribution	1,487,586	1,320,329	1,555,107	1,379,457
10	General	401,671	351,404	460,053	400,263
11	Common	256,562	224,610	313,068	272,609
12	TOTAL Reserve for Depreciation	$9,269,103	$8,117,836	$9,931,327	$8,640,889
	Net Utility Plant in Service				
13	Production	$5,004,683	$4,371,845	$5,630,361	$4,882,394
14	Transmission	2,836,774	2,505,149	2,887,974	2,531,084
15	Distribution	2,560,554	2,223,336	2,672,226	2,316,480
16	General	542,980	475,799	551,354	480,300
17	Common	422,526	369,939	456,622	397,590
18	Net Utility Plant in Service	$11,367,517	$9,946,067	$12,198,537	$10,607,849
19	Utility Plant Held for Future Use	$0	$0	$0	$0
20	Construction Work in Progress	$717,478	$624,621	$697,499	$604,068
21	Less: Accumulated Deferred Income Taxes	$2,772,579	$2,434,475	$2,648,502	$2,328,990
22	Cash Working Capital	($190,052)	($169,536)	($149,999)	($133,489)
	Other Rate Base Items:				
23	Materials and Supplies	$191,665	$168,024	$176,908	$153,932
24	Fuel Inventory	78,920	68,794	75,984	65,875
25	Non-Plant Assets & Liabilities	64,954	54,318	52,595	43,291
26	Customer Advances	(12,320)	(9,860)	(11,777)	(9,797)
27	Interest on Customer Deposits	(73,141)	(72,959)	(54,994)	(54,826)
28	Prepaids and Other	82,756	72,393	80,187	69,703
29	Regulatory Amortizations	0	0	0	0
30	Total Other Rate Base Items	$332,835	$280,708	$318,903	$268,178
31	Total Average Rate Base	$9,455,200	$8,247,385	$10,416,439	$9,017,617

(1) Revenues and expenses for riders have been included where applicable.

2020 Unadjusted Test Year versus Final Adjusted Test Year
($000's)

		Base				Adjustment	Amortization					Rider Removals		Secondary Calculations				
Line No.	Description	Unadjusted w/o NOL & 199	ADIT Prorate for IRS	Unadjusted NOL & 199	Total Unadjusted	Mankato Energy	Aurora	LED Street Lighting	NOL ADIT ARAM	PI EPU Recovery	Sherco 3 Depr Deferral	Rider: RES	Rider: TCR	ADIT Prorate for IRS	Cash Working Capital	Change in Cost of Capital	Net Operating Loss	2020 Test Year
	Work Paper Reference					**WP A-22**	**WP A-33**	**WP A-34**	**WP A-35**	**WP A-36**	**WP A-38**	**WP A-40**	**WP A-41**	**WP A-43**	**WP A-44**	**WP A-46**	**WP A-45**	
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
1	Plant as booked																	
2	Production	12,114,337			12,114,337	(569,751)						(429,143)						11,115,442
3	Transmission	3,281,379			3,281,379							(10,929)	(1,851)					3,268,599
4	Distribution	3,883,261			3,883,261													3,883,261
5	General	958,608			958,608								(17,721)					940,887
6	Common	750,280			750,280													750,280
7	Total Utility Plant in Service	20,987,865			20,987,865	(569,751)						(440,073)	(19,573)					19,958,469
8																		
9	Reserve for Depreciation																	
10	Production	6,343,405			6,343,405	(14,716)						(1,931)						6,326,757
11	Transmission	728,397			728,397							(10)						728,387
12	Distribution	1,446,041			1,446,041													1,446,041
13	General	461,045			461,045								(1,072)					459,973
14	Common	334,261			334,261													334,261
15	Total Reserve for Depreciation	9,313,149			9,313,149	(14,716)						(1,940)	(1,072)					9,295,420
16																		
17	Net Utility Plant																	
18	Production	5,770,932			5,770,932	(555,035)						(427,213)						4,788,685
19	Transmission	2,552,983			2,552,983							(10,920)	(1,851)					2,540,212
20	Distribution	2,437,219			2,437,219													2,437,219
21	General	497,563			497,563								(16,649)					480,914
22	Common	416,019			416,019													416,019
23	Net Utility Plant in Service	11,674,717			11,674,717	(555,035)						(438,132)	(18,500)					10,663,050
24																		
25	Utility Plant Held for Future Use																	
26																		
27	Construction Work in Progress	521,530			521,530	(88)						(131,463)	(25,991)					363,989
28																		
29	Less: Accumulated Deferred Income Taxes	2,521,395	(18,918)	(219,022)	2,283,455	(7,566)				16,310	2,977	(19,635)	(719)	13,615			12,565	2,301,002
30																		
31	Other Rate Base Items																	
32	Cash Working Capital	(129,815)			(129,815)										10,666			(119,149)
33	Materials and Supplies	153,932			153,932													153,932
34	Fuel Inventory	65,875			65,875													65,875
35	Non Plant Assets and Liabilities	60,475			60,475													60,475
36	Customer Advances	(9,797)			(9,797)													(9,797)
37	Customer Deposits	(54,826)			(54,826)													(54,826)
38	Prepayments	68,747			68,747													68,747
39	Regulatory Amortizations						1,488	419	46,509	39,896	7,295							95,608
40	Total Other Rate Base	154,590			154,590		1,488	419	46,509	39,896	7,295				10,666			260,864
41																		
42	Total Average Rate Base	9,829,442	18,918	219,022	10,067,382	(547,556)	1,488	419	46,509	23,587	4,319	(549,960)	(43,772)	(13,615)	10,666		(12,565)	8,986,901

Northern States Power Company
Electric Utility - State of Minnesota
RATE BASE SCHEDULES
RATE BASE ADJUSTMENT SCHEDULES
2021 Unadjusted Test Year versus Final Adjusted 2021 Plan Year
($000's)

Line No.	Description	Base				Adjustment	Amortization					Rider Removals		Secondary Calculations				2021 Plan Year
		Unadjusted w/o NOL & 199 Unadjusted	ADIT Prorate for IRS	Unadjusted NOL & 199	Total Unadjusted	Mankato Energy	Aurora	LED Street Lighting	NOL ADIT ARAM	PI EPU Recovery	Sherco 3 Depr Deferral	Rider: RES	Rider: TCR	ADIT Prorate for IRS	Cash Working Capital	Change in Cost of Capital	Net Operating Loss	
	Work Paper Reference					WP A-22	WP A-33	WP A-34	WP A-35	WP A-36	WP A-38	WP A-40	WP A-41	WP A-43	WP A-44	WP A-46	WP A-45	
1		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
2	Plant as booked																	
3	Production	13,030,270			13,030,270	(572,869)						(976,276)						11,481,125
4	Transmission	3,417,466			3,417,466							(31,312)	(26,894)					3,359,259
5	Distribution	4,136,381			4,136,381													4,136,381
6	General	1,044,195			1,044,195								(33,992)					1,010,202
7	Common	830,985			830,985													830,985
8	Total Utility Plant in Service	22,459,297			22,459,297	(572,869)						(1,007,589)	(60,887)					20,817,953
9																		
10	Reserve for Depreciation																	
11	Production	6,830,940			6,830,940	(33,129)						(22,837)						6,774,974
12	Transmission	788,218			788,218							(260)	(22)					787,936
13	Distribution	1,519,172			1,519,172													1,519,172
14	General	523,622			523,622								(3,605)					520,017
15	Common	402,441			402,441													402,441
16	Total Reserve for Depreciation	10,064,393			10,064,393	(33,129)						(23,097)	(3,628)					10,004,539
17																		
18	Net Utility Plant																	
19	Production	6,199,330			6,199,330	(539,740)						(953,439)						4,706,151
20	Transmission	2,629,248			2,629,248							(31,052)	(26,872)					2,571,324
21	Distribution	2,617,209			2,617,209													2,617,209
22	General	520,573			520,573								(30,387)					490,186
23	Common	428,545			428,545													428,545
24	Net Utility Plant in Service	12,394,904			12,394,904	(539,740)						(984,491)	(57,259)					10,813,415
25																		
26	Utility Plant Held for Future Use																	
27																		
28	Construction Work in Progress	466,594			466,594	(10)						(37,113)	(11,668)					417,804
29																		
30	Less: Accumulated Deferred Income Taxes	2,754,586	(23,090)	(517,285)	2,214,211	(13,551)				15,131	2,771	(79,565)	(2,504)	23,467			27,678	2,187,638
31																		
32	Other Rate Base Items																	
33	Cash Working Capital	(139,445)			(139,445)										12,415			(127,030)
34	Materials and Supplies	153,932			153,932													153,932
35	Fuel Inventory	65,875			65,875													65,875
36	Non Plant Assets and Liabilities	81,070			81,070													81,070
37	Customer Advances	(9,797)			(9,797)													(9,797)
38	Customer Deposits	(54,826)			(54,826)													(54,826)
39	Prepayments	67,952			67,952													67,952
40	Regulatory Amortizations						492	252	44,240	37,012	6,792							88,788
41	Total Other Rate Base	164,760			164,760		492	252	44,240	37,012	6,792				12,415			265,964
42																		
43	Total Average Rate Base	10,271,673	23,090	517,285	10,812,048	(526,198)	492	252	44,240	21,882	4,021	(942,039)	(66,423)	(23,467)	12,415		(27,678)	9,309,544

Northern States Power Company
Electric Utility - State of Minnesota
RATE BASE SCHEDULES
RATE BASE ADJUSTMENT SCHEDULES
2022 Unadjusted Test Year versus Final Adjusted 2022 Plan Year
($000's)

Docket No. E002/GR-19-564
Financial Information
Schedule C

Line No.	Description	Base				Adjustment	Amortization					Rider Removals		Secondary Calculations				2022 Plan Year
		Unadjusted w/o NOL & 199 Unadjusted	ADIT Prorate for IRS	Unadjusted NOL & 199	Total Unadjusted	Mankato Energy	Aurora	LED Street Lighting	NOL ADIT ARAM	PI EPU Recovery	Sherco 3 Depr Deferral	Rider: RES	Rider: TCR	ADIT Prorate for IRS	Cash Working Capital	Change in Cost of Capital	Net Operating Loss	
	Work Paper Reference					WP A-22	WP A-33	WP A-34	WP A-35	WP A-36	WP A-38	WP A-40	WP A-41	WP A-43	WP A-44	WP A-46	WP A-45	
1		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
2	Plant as booked																	
3	Production	13,342,206			13,342,206	(576,195)						(1,092,206)						11,673,805
4	Transmission	3,582,112			3,582,112							(40,767)	(51,162)					3,490,183
5	Distribution	4,500,875			4,500,875													4,500,875
6	General	1,116,125			1,116,125								(35,666)					1,080,459
7	Common	954,870			954,870													954,870
8	Total Utility Plant in Service	23,496,188			23,496,188	(576,195)						(1,132,973)	(86,829)					21,700,191
9																		
10	Reserve for Depreciation																	
11	Production	7,253,560			7,253,560	(51,628)						(65,650)						7,136,281
12	Transmission	850,218			850,218							(944)	(590)					848,684
13	Distribution	1,597,559			1,597,559													1,597,559
14	General	589,371			589,371								(6,649)					582,722
15	Common	476,634			476,634													476,634
16	Total Reserve for Depreciation	10,767,342			10,767,342	(51,628)						(66,594)	(7,239)					10,641,880
17																		
18	Net Utility Plant																	
19	Production	6,088,646			6,088,646	(524,567)						(1,026,556)						4,537,524
20	Transmission	2,731,894			2,731,894							(39,823)	(50,572)					2,641,499
21	Distribution	2,903,316			2,903,316													2,903,316
22	General	526,754			526,754								(29,018)					497,737
23	Common	478,235			478,235													478,235
24	Net Utility Plant in Service	12,728,846			12,728,846	(524,567)						(1,066,378)	(79,590)					11,058,311
25																		
26	Utility Plant Held for Future Use																	
27																		
28	Construction Work in Progress	508,517			508,517	(1)						(685)	59					507,890
29																		
30	Less: Accumulated Deferred Income Taxes	2,815,347	(8,736)	(687,629)	2,118,982	(18,741)				13,952	2,566	(146,990)	(4,758)	17,463			33,232	2,015,705
31																		
32	Other Rate Base Items																	
33	Cash Working Capital	(154,456)			(154,456)										13,568			(140,888)
34	Materials and Supplies	153,932			153,932													153,932
35	Fuel Inventory	65,875			65,875													65,875
36	Non Plant Assets and Liabilities	90,346			90,346													90,346
37	Customer Advances	(9,797)			(9,797)													(9,797)
38	Customer Deposits	(54,826)			(54,826)													(54,826)
39	Prepayments	68,129			68,129													68,129
40	Regulatory Amortizations							84	41,972	34,128	6,289							82,473
41	Total Other Rate Base	159,203			159,203			84	41,972	34,128	6,289				13,568			255,244
42																		
43	Total Average Rate Base	10,581,220	8,736	687,629	11,277,585	(505,827)		84	41,972	20,177	3,723	(920,073)	(74,773)	(17,463)	13,568		(33,232)	9,805,740

Adjustment Type	Adjustment	Adjustment Description
Adjustment	Mankato Energy Center	Removes capital and O&M for MEC and adds cost of MEC I and II PPA
Adjustment	Nonplant and Other Rate Base	Non-Plant Excess ADIT
Amortizations	Aurora	Reflects the Aurora deferral requested in 2020-2022 MYRP
Amortizations	LED Street Lighting	Reflects the LED Street Lighting deferral requested in 2020-2022 MYRP
Amortizations	NOL ADIT ARAM	Reflects the amorization level per Commission's Order in Docket No. E,G-999/CI-17-895 in the 2020-2022 MYRP
Amortizations	Sherco 3 Deferral	Reflects the Sherco 3 costs deferred in Docket No. E002/GR-13-868 in the 2020-2022 MYRP
Amortizations	PI EPU Deferral	Reflects the PI EPU costs deferred in Docket No. E002/GR-13-868 in the 2020-2022 MYRP
Rider Removals	RES Rider Removal	Removes costs and revenues related to items being recovered in rate riders
Rider Removals	TCR Rider Removal	Removes costs and revenues related to items being recovered in rate riders

Northern States Power Company
Electric Utility - State of Minnesota
RATE BASE SCHEDULES
RATE BASE ADJUSTMENT SCHEDULES
Unadjusted Projected Fiscal Year 2019 versus Adjusted Projected Fiscal Year 2019
($000's)

Docket No. E002/GR-19-564
Financial Information
Schedule C - 2019

Line No.	Description	Base	Secondary Calculations			Adjustment	Amortization					Removals		Secondary Calculations			Adjusted Projected Fiscal Year 2019
		Unadjusted w/o NOL & 199	ADIT Prorate for IRS	Unadjusted NOL & 199	Total Unadjusted	Mankato Energy	Aurora	LED Street Lighting	NOL ADIT ARAM	PI EPU Recovery	Sherco 3 Depr Deferral	Rider: RES	Rider: TCR	ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	
						WP A-22	WP A-33	WP A-34	WP A-35	WP A-36	WP A-38	WP A-40	WP A-41	WP A-43	WP A-44	WP A-45	
1		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
2	Plant as booked																
3	Production	10,803,218			10,803,218	(284,838)						(97)					10,518,283
4	Transmission	3,198,821			3,198,821								(323)				3,198,497
5	Distribution	3,695,938			3,695,938												3,695,938
6	General	880,563			880,563								(934)				879,629
7	Common	670,199			670,199												670,199
8	Total Utility Plant in Service	19,248,739			19,248,739	(284,838)						(97)	(1,258)				18,962,545
9																	
10	Reserve for Depreciation																
11	Production	5,920,824			5,920,824	(2,662)						(0)					5,918,162
12	Transmission	667,737			667,737												667,737
13	Distribution	1,379,457			1,379,457												1,379,457
14	General	400,263			400,263								(12)				400,250
15	Common	272,609			272,609												272,609
16	Total Reserve for Depreciation	8,640,889			8,640,889	(2,662)						(0)	(12)				8,638,215
17																	
18	Net Utility Plant																
19	Production	4,882,394			4,882,394	(282,177)						(97)					4,600,121
20	Transmission	2,531,084			2,531,084								(323)				2,530,761
21	Distribution	2,316,480			2,316,480												2,316,480
22	General	480,300			480,300								(922)				479,379
23	Common	397,590			397,590												397,590
24	Net Utility Plant in Service	10,607,849			10,607,849	(282,177)						(97)	(1,245)				10,324,331
25																	
26	Utility Plant Held for Future Use																
27																	
28	Construction Work in Progress	604,068			604,068	(259)						(129,423)	(22,441)				451,945
29																	
30	Less: Accumulated Deferred Income Taxes	2,335,542	1,950	(8,503)	2,328,990	(2,199)				17,489	3,182	689	(84)	1,259		3,840	2,353,166
31																	
32	Other Rate Base Items																
33	Cash Working Capital	(133,489)			(133,489)										14,272		(119,217)
34	Materials and Supplies	153,932			153,932												153,932
35	Fuel Inventory	65,875			65,875												65,875
36	Non Plant Assets and Liabilities	43,291			43,291												43,291
37	Customer Advances	(9,797)			(9,797)												(9,797)
38	Customer Deposits	(54,826)			(54,826)												(54,826)
39	Prepayments	69,703			69,703												69,703
40	Regulatory Amortizations						1,603	252	48,778	42,781	7,799						101,211
41	Total Other Rate Base	134,689			134,689		1,603	252	48,778	42,781	7,799				14,272		250,172
42																	
43	Total Average Rate Base	9,011,065	(1,950)	8,503	9,017,617	(280,236)	1,603	252	48,778	25,292	4,616	(130,209)	(23,603)	(1,259)	14,272	(3,840)	8,673,282

Adjustment Type	Adjustment	Adjustment Description
Adjustment	Mankato Energy Center	Removes capital and O&M for MEC and adds cost of MEC I and II PPA
Amortizations	Aurora	Reflects the Aurora deferral requested in 2020-2022 MYRP
Amortizations	LED Street Lighting	Reflects the LED Street Lighting deferral requested in 2020-2022 MYRP
Amortizations	NOL ADIT ARAM	Reflects the amorization level per Commission's Order in Docket No. E,G-999/CI-17-895 in the 2020-2022 MYRP
Amortizations	Sherco 3 Deferral	Reflects the Sherco 3 costs deferred in Docket No. E002/GR-13-868 in the 2020-2022 MYRP
Amortizations	PI EPU Deferral	Reflects the PI EPU costs deferred in Docket No. E002/GR-13-868 in the 2020-2022 MYRP
Rider Removals	RES Rider Removal	Removes costs and revenues related to items being recovered in rate riders
Rider Removals	TCR Rider Removal	Removes costs and revenues related to items being recovered in rate riders

Unadjusted Most Recent Fiscal Year 2018 versus Adjusted Most Recent Fiscal Year 2018
($000's)

Line No.	Description	Base			Amortization				Removals		Secondary Calculations		Adjusted Most Recent Fiscal Year 2018
		Unadjusted w/o NOL & 199	Unadjusted NOL & 199	Unadjusted Most Recent Fiscal Year 2018	NOL ADIT ARAM	Nonplant and Other Rate Base	PI EPU Recovery	Sherco 3 Depr Deferral	Rider: RES	Rider: TCR	Cash Working Capital	Net Operating Loss	
		(1)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	Plant as booked												
2	Production	9,972,085		9,972,085									9,972,085
3	Transmission	3,126,401		3,126,401									3,126,401
4	Distribution	3,543,665		3,543,665									3,543,665
5	General	827,203		827,203									827,203
6	Common	594,549		594,549									594,549
7	Total Utility Plant in Service	18,063,903		18,063,903									18,063,903
8													
9	Reserve for Depreciation												
10	Production	5,600,240		5,600,240									5,600,240
11	Transmission	621,253		621,253									621,253
12	Distribution	1,320,329		1,320,329									1,320,329
13	General	351,404		351,404									351,404
14	Common	224,610		224,610									224,610
15	Total Reserve for Depreciation	8,117,836		8,117,836									8,117,836
16													
17	Net Utility Plant												
18	Production	4,371,845		4,371,845									4,371,845
19	Transmission	2,505,149		2,505,149									2,505,149
20	Distribution	2,223,336		2,223,336									2,223,336
21	General	475,799		475,799									475,799
22	Common	369,939		369,939									369,939
23	Net Utility Plant in Service	9,946,067		9,946,067									9,946,067
24													
25	Utility Plant Held for Future Use												
26													
27	Construction Work in Progress	624,621		624,621					(37,165)	(13,351)			574,105
28													
29	Less: Accumulated Deferred Income Taxes	2,322,476	111,999	2,434,475		10,850	18,668	3,421	56	(41)		(1,817)	2,465,612
30													
31	Other Rate Base Items												
32	Cash Working Capital	(169,536)		(169,536)							(2,375)		(171,911)
33	Materials and Supplies	168,024		168,024									168,024
34	Fuel Inventory	68,794		68,794									68,794
35	Non Plant Assets and Liabilities	54,318		54,318									54,318
36	Customer Advances	(9,860)		(9,860)									(9,860)
37	Customer Deposits	(72,959)		(72,959)									(72,959)
38	Prepayments	72,393		72,393									72,393
39	Regulatory Amortizations				51,047		45,665	8,302					105,013
40	Total Other Rate Base	111,172		111,172	51,047		45,665	8,302			(2,375)		213,810
41													
42	Total Average Rate Base	8,359,384	(111,999)	8,247,385	51,047	(10,850)	26,997	4,881	(37,221)	(13,309)	(2,375)	1,817	8,268,371

Adjustment Type	Adjustment	Adjustment Description
Amortizations	NOL ADIT ARAM	Reflects the amorization level per Commission's Order in Docket No. E,G-999/CI-17-895 in the 2020-2022 MYRP
Amortizations	Sherco 3 Deferral	Reflects the Sherco 3 costs deferred in Docket No. E002/GR-13-868 in the 2020-2022 MYRP
Amortizations	PI EPU Deferral	Reflects the PI EPU costs deferred in Docket No. E002/GR-13-868 in the 2020-2022 MYRP
Rider Removals	RES Rider Removal	Removes costs and revenues related to items being recovered in rate riders
Rider Removals	TCR Rider Removal	Removes costs and revenues related to items being recovered in rate riders

PLANT IN SERVICE

Plant in Service represents facilities that are used and useful in providing utility service, including facilities currently in service, capital projects completed but not classified, and property held for future use. Plant in Service represents historical and projected additions and retirements to NSP's electric utility. Plant additions represent plant that is already in use (capitalized) or will become useful in the future, but has not become part of the official plant accounting records of the Company. Plant retirements represent plant taken out of service.

The electric utility plant is functionalized according to its use into the following areas: production, transmission, distribution, general, and common use. Plant in Service investment for each function is calculated using a beginning-of-year and end-of-year average. The historical plant balances for the electric utility correspond directly to the Company's books and records. Actual additions and retirements through December 31, 2018, are used as a starting point for the projected year-end amounts for the projected 2019 fiscal year, the 2020 proposed test year, and the 2021 and 2022 plan years. Projected additions and retirements are then developed using the Company's construction budget. Additions and retirements are developed on a monthly basis and are used to compute the Plant in Service amounts for the projected fiscal year for the electric utility.

ACCUMULATED PROVISION FOR DEPRECIATION

The Accumulated Provision for Depreciation represents the recovery of the amount invested in Plant in Service. The balances in this account include the historical and projected retirements and net salvage of NSP's electric utility Plant in Service by function.

Accumulated Provision for Depreciation is functionalized on the same basis as Plant in Service. Accumulated Provision for Depreciation for the projected year is calculated using a beginning-of-year and end-of-year average. The historical and projected Accumulated Provisions for Depreciation are based upon the annual straight line depreciation rates that are developed for each functional class and certified by the Minnesota Public Utilities Commission.

HELD FOR FUTURE USE

Property Held for Future Use includes land, land rights and plant acquired but never used in providing utility service, and plant removed from service but held pending its reuse in the future under a definite plan of action.

Property Held for Future Use balances are shown by function. The projected fiscal year amount reflects an average of the beginning-of-year and end-of-year amounts.

CONSTRUCTION WORK IN PROGRESS

Construction Work in Progress consists of projects that have not been completed, or have been completed, but have not yet been classified to Plant in Service.

Construction Work in Progress balances are shown by function. The projected fiscal year amount reflects an average of the beginning-of-year and end-of-year amounts. When a project has been completed and is ready to be capitalized to Plant in Service, the capital budget system reflects the lag that actually occurs before a project is recorded as Plant in Service.

ACCUMULATED DEFERRED INCOME TAXES

Accumulated Deferred Income Taxes represent the accumulated annual net provision for deferred income taxes relating to liberalized depreciation, repair allowance, and other capitalized items including property tax, payroll tax, sales tax, and pensions. Accumulated Deferred Income Taxes reflect timing differences between book and tax depreciation lives, and other non-plant book/tax timing differences.

The balance in this account is functionalized on the same basis as Plant in Service. NSP maintains its plant investments, both historical and projected, at a level of detail such that an accurate calculation of book depreciation and tax depreciation may be made. The Accumulated Deferred Income Taxes for the projected year are calculated using a beginning-of-year and end-of-year average and are deducted from net Plant in Service.

CASH WORKING CAPITAL

Cash Working Capital represents the cash investment requirement to pay for operating expenses, to maintain compensating cash balances, and to provide for other cash needs, such as employee advances.

Cash Working Capital for the projected fiscal year is determined using a lead/lag study on projected fiscal year revenues (assuming proposed level of rates) and projected fiscal year expenses. The revenue lead versus the expense lag is measured and the difference is applied to the projected fiscal year expense categories.

MATERIALS AND SUPPLIES

Materials and Supplies reflect balances from electric transmission and distribution and meter accounts. Materials and Supplies are used to maintain and repair existing plant and in the construction of new facilities.

The amount included in Materials and Supplies for the projected year represents a thirteen-month average of the projected balances in the above-mentioned accounts.

NON-PLANT ASSETS AND LIABILITIES

The balance in this account represents accrued liabilities for:
<u>Pension</u> - The amount of internal pension accrual which is an increase to rate base.
<u>Accrued Vacation Reserve</u> - This item represents the liability for earned vacation not taken. The amount is a decrease to rate base.

<u>SFAS 106</u> - This item represents the test year average post-retirement benefits expense (excluding pension costs) to be accrued and collected in accordance with SFAS 106, but not paid. Until the benefits are actually paid or remitted to a plan trustee, the accrued expenses represent a source of cash provided by the Company's customers, and as such, are reflected as a reduction to rate base.

SFAS 112 - This item represents the test year average post-employment expense to be accrued and collected in accordance with SFAS 112, but not paid. Until the benefits are actually paid, the accrued expenses represent a source of cash and thus reflected as a reduction to rate base.
All Other Adjustments - This item represents the test year average of all other non-plant assets and liabilities not specifically identified above. The amount represents a source of cash and is being reflected as a reduction of rate base.

PREPAYMENTS

Prepayments include payments made in prior periods for such items as prepaid insurance, postage, rent, regulatory fee, VEBA trust, workers compensation and taxes.

Prepayments for the projected year are based upon the most recent thirteen-month historical period.

NEW BUSINESS CIAC

This item represents removing expenses that will be charged as a contribution in aid of construction based on a proposed change in rate design.

CUSTOMER ADVANCES/DEPOSITS

This liability account represents a non-investor source of capital. The amount in this account represents balances that may be refunded to customers who have advanced funds as a deposit or for construction of facilities beyond NSP’s service extension policy. Customer advances are a negative adjustment to rate base.

OTHER WORKING CAPITAL

Other Working Capital consist of various asset and liability accounts that have been allocated or assigned to the electric utility. The inclusion of these items reflects additional sources (or uses) of investor and non-investor supplied funds.

Other Working Capital included in the test year reflects the thirteen-month average of historical balances for these items.

Line No.	Description	Allocation Basis
	The allocation factors on this page were used to determine Minnesota jurisdictional rate base amounts for all of the years presented in these schedules. Accounts not on this page have been directly assigned to jurisdictions.	Unadjusted Test Year 2020
	The following allocation factors are used to compute Minnesota jurisdictional amounts for Plant-in-Service, Accumulated Depreciation, Accumulated Deferred Income Tax and Construction Work in Progress:	
1	Production	Demand - Production Energy
2	Transmission	Demand - Transmission
3	General	
	Production	Demand - Production
	Transmission	Demand - Transmission
	Other	Customers
4	Common	
	Production	Demand - Production
	Transmission	Demand - Transmission
	Other	Customers
	In addition, the following allocation factors are used to compute Minnesota jurisdictional amounts:	
5	Other Rate Base:	
	Materials & Supplies	Demand - Production Demand - Transmission Customers
	Non-Plant Assets & Liabilities	Demand - Production Demand - Transmission Customers Energy
	Prepayments	Demand - Production Demand - Transmission Customers
	Fuel Inventory	Energy

Northern States Power Company
Electric Utility - State of Minnesota
RATE BASE SCHEDULES
RATE BASE JURISDICTIONAL ALLOCATION FACTORS

	Most Recent Fiscal Year 2018				Projected Fiscal Year 2019				Proposed Test Year 2020, Plan Years 2021 & 2022			
Line No.	Allocation Factor	st Year 2020, F Utility	Minnesota Jurisdiction	Allocation Factor	Allocation Factor	Total Utility	Minnesota Jurisdiction	Allocation Factor	Allocation Factor	Total Utility	Minnesota Jurisdiction	Allocation Factor
1	Demand - Prod(1)	67,498,442	59,188,021	87.6880%	Demand - Prod(1)	64,459,483	56,079,105	86.9990%	Demand - Prod(1)	64,459,483	56,079,105	86.9990%
2	Demand - Tran (2)	67,498,442	59,188,021	87.6880%	Demand - Tran (2)	64,459,483	56,079,105	86.9990%	Demand - Tran (2)	64,459,483	56,079,105	86.9990%
3	Energy (3)	35,974,452	31,358,488	87.1688%	Energy (3)	34,275,058	29,715,088	86.6960%	Energy (3)	34,275,058	29,715,088	86.6960%
4	Customers(4)	1,478,542	1,290,003	87.2483%	Customers(4)	1,503,224	1,311,282	87.2313%	Customers(4)	1,503,224	1,311,282	87.2313%

(1) Demand w/o Contract Services
(2) Demand
(3) Energy
(4) Average number of Customers

		Unadjusted Test Year 2020, Plan Years 2021 & 2022		
Line No.	Allocation Factor	Total Utility	Minnesota Jurisdiction	Allocation Factor
1	Demand - Production	64,459,483	56,079,105	86.9990%
2	Demand - Transmission	64,459,483	56,079,105	86.9990%
3	Energy	34,275,058	29,715,088	86.6960%
4	Customers	1,503,224	1,311,282	87.2313%

(1) Demand w/o Contract Services
(2) Demand
(3) Energy
(4) Average number of Customers

OPERATING INCOME SCHEDULES
(PART 7825.4100)

The following operating income schedules as required by parts 7825.3800 and 7825.4100 shall be filed:

A. A summary schedule of jurisdictional operating income statements which reflect proposed test year operating income, and unadjusted jurisdictional operating income for the most recent fiscal year and the projected fiscal year calculated using present rates.

B. For multi-jurisdictional utilities only, a schedule showing the comparison of total utility and unadjusted jurisdictional operating income statement for the test year, for the most recent fiscal year and the projected fiscal year. In addition, the schedule shall provide the proposed adjustments, if any, to jurisdictional operating income for the test year together with the proposed operating income statement.

C. For investor-owned utilities only, a summary schedule showing the computation of total utility and allocated Minnesota jurisdictional federal and state income tax expense and deferred income taxes for the test year, the most recent fiscal year, and the projected fiscal year. This summary schedule shall be supported by a detailed schedule, showing the development of the combined federal and state income tax rates.

D. A summary schedule of adjustments, if any, to jurisdictional test year operating income and detailed schedules for each adjustment providing an adjustment title, purpose and description of the adjustment, and summary calculations.

E. A schedule summarizing the assumptions made and the approaches used in projecting each major element of operating income. Such assumptions and approaches shall be identified and quantified into two categories: known changes from the most recent fiscal year and projected changes.

OPERATING INCOME SCHEDULES (Continued)
(PART 7825.4100)

F. For multi-jurisdictional utilities only, a schedule providing, by operating income element, the factor or factors used in allocating total utility operating income to Minnesota jurisdiction. This schedule shall be supported by a schedule which sets forth the statistics used in determining each jurisdictional allocation factor for the test year, the most recent fiscal year, and the projected fiscal year.

Northern States Power Company
Electric Utility - State of Minnesota
OPERATING INCOME SCHEDULES
JURISDICTIONAL STATEMENT OF OPERATING INCOME
($000's)

Docket No. E002/GR-19-564
Financial Information
Schedule A-1

Line No.	Description	Adjusted (1) Most Recent Fiscal Year 2018 (A)	Adjusted (1) Projected Fiscal Year 2019 (B)	Adjusted (1) Proposed Test Year 2020 (C)	Adjusted (1) Plan Year 2021 (D)	Adjusted (1) Plan Year 2022 (E)
	Operating Revenues					
1	Retail	$3,088,090	$3,264,675	$3,120,645	$3,080,450	$3,068,944
2	CIP Revenue Adjustment	0	0	0	0	0
3	Interdepartmental & Transportation	692	464	494	494	494
4	Other Operating	656,690	580,693	545,018	560,238	574,740
5	Gross Earnings Tax	0	0	0	0	0
6	**Total Operating Revenues**	$3,745,473	$3,845,833	$3,666,158	$3,641,182	$3,644,178
	Expenses					
	Operating Expenses:					
7	Fuel & Purchased Energy	$1,079,928	$982,354	$937,629	$937,984	$937,289
8	Power Production	599,460	588,266	604,726	628,551	637,764
9	Transmission	231,048	253,966	255,621	260,272	269,688
10	Distribution	108,027	110,471	114,249	132,140	127,086
11	Customer Accounting	49,110	47,821	48,973	48,931	43,907
12	Customer Service & Information	146,674	133,837	105,520	105,532	105,572
13	Sales, Econ Dvlp & Other	46	13	(6)	(5)	(5)
14	Administrative & General	212,730	211,324	246,966	252,269	260,301
15	Total Operating Expenses	$2,427,024	$2,328,052	$2,313,678	$2,365,673	$2,381,602
16	Depreciation	$575,233	$608,386	$683,392	$719,524	$760,859
17	Amortizations	$67,177	$54,903	$43,948	$43,475	$44,757
	Taxes:					
18	Property	$187,821	$176,526	$178,357	$183,524	$197,091
19	Gross Earnings	0	0	0	0	0
20	Deferred Income Tax & ITC	581	(20,260)	(71,438)	(172,672)	(190,897)
21	Federal & State Income Tax	(18,915)	52,736	(6,184)	59,576	56,478
22	Payroll & Other	27,428	27,341	27,259	27,352	27,435
23	Total Taxes	$196,915	$236,344	$127,994	$97,781	$90,108
24	**Total Expenses**	$3,266,350	$3,227,685	$3,169,012	$3,226,453	$3,277,326
25	AFUDC	29,731	24,842	28,846	31,000	33,500
26	**Total Operating Income**	$508,854	$642,990	$525,991	$445,729	$400,352

Note: Revenues reflect calendar month sales.

(1) Revenues and expenses for riders have been included where applicable.

Northern States Power Company | **Docket No. E002/GR-19-564**
Electric Utility - State of Minnesota | **Financial Information**
OPERATING INCOME SCHEDULES | **Schedule A-2**
JURISDICTIONAL STATEMENT OF OPERATING INCOME
($000's)

Line No.	Description	Unadjusted (1) Most Recent Fiscal Year 2018 (A)	Unadjusted (1) Projected Fiscal Year 2019 (B)	Unadjusted (1) Proposed Test Year 2020 (C)	Unadjusted (1) Plan Year 2021 (D)	Unadjusted (1) Plan Year 2022 (E)
	Operating Revenues					
1	Retail	$3,092,821	$3,272,609	$3,197,649	$3,183,551	$3,165,850
2	CIP Revenue Adjustment	0	0	0	0	0
3	Interdepartmental & Transportation	692	464	494	494	494
4	Other Operating	777,610	750,632	765,610	800,891	825,186
5	Gross Earnings Tax	0	0	0	0	0
6	**Total Operating Revenues**	$3,871,124	$4,023,706	$3,963,754	$3,984,937	$3,991,531
	Expenses					
	Operating Expenses:					
7	Fuel & Purchased Energy	$1,122,180	$1,080,989	$1,062,005	$1,062,360	$1,061,665
8	Power Production	603,548	580,153	563,360	599,485	610,736
9	Transmission	324,762	348,026	354,649	360,238	370,336
10	Distribution	108,027	110,471	114,249	132,140	127,086
11	Customer Accounting	49,110	47,821	48,973	48,931	43,907
12	Customer Service & Information	102,802	104,125	95,818	138,556	144,996
13	Sales, Econ Dvlp & Other	0	0	0	0	0
14	Administrative & General	243,057	240,888	262,005	268,528	277,657
15	Total Operating Expenses	$2,553,485	$2,512,474	$2,501,059	$2,610,238	$2,636,383
16	Depreciation	$575,233	$613,831	$707,973	$779,626	$832,484
17	Amortizations	$33,535	$40,312	$34,361	$33,888	$37,139
	Taxes:					
18	Property	$176,772	$176,541	$179,102	$187,066	$202,475
19	Gross Earnings	0	0	0	0	0
20	Deferred Income Tax & ITC	6,716	(23,290)	(28,495)	(99,396)	(131,615)
21	Federal & State Income Tax	(14,198)	49,803	(35,614)	(82,848)	(93,208)
22	Payroll & Other	27,477	27,374	27,290	27,384	27,468
23	Total Taxes	$196,767	$230,428	$142,283	$32,206	$5,119
24	**Total Expenses**	$3,359,021	$3,397,044	$3,385,676	$3,455,958	$3,511,125
25	AFUDC	29,731	25,603	28,853	31,116	33,511
26	**Total Operating Income**	$541,834	$652,264	$606,930	$560,095	$513,917

Note: Revenues reflect calendar month sales.

(1) Revenues and expenses for riders have been included where applicable.

Northern States Power Company
Electric Utility - State of Minnesota
OPERATING INCOME SCHEDULES
STATEMENT OF OPERATING INCOME
($000's)

Docket No. E002/GR-19-564
Financial Information
Schedule B-1

		Adjusted (1) Proposed Test Year 2020		Adjusted (1) Plan Year 2021		Adjusted (1) Plan Year 2022	
Line No.	Description	Total Utility (A)	Minnesota Jurisdiction (B)	Total Utility (C)	Minnesota Jurisdiction (D)	Total Utility (E)	Minnesota Jurisdiction (F)
	Operating Revenues						
1	Retail	$3,560,669	$3,120,645	$3,517,219	$3,080,450	$3,507,504	$3,068,944
2	CIP Revenue Adjustment	0	0	0	0	0	0
3	Interdepartmental & Transportation	494	494	494	494	494	494
4	Other Operating	638,627	545,018	657,287	560,238	674,636	574,740
5	Gross Earnings Tax	0	0	0	0	0	0
6	**Total Operating Revenues**	$4,199,791	$3,666,158	$4,175,000	$3,641,182	$4,182,634	$3,644,178
	Expenses						
	Operating Expenses:						
7	Fuel & Purchased Energy	$1,055,593	$937,629	$1,056,002 #	$937,984	$1,055,201	$937,289
8	Power Production	695,064	604,726	724,447	628,551	735,402	637,764
9	Transmission	307,073	255,621	312,669	260,272	323,598	269,688
10	Distribution	131,562	114,249	151,911	132,140	146,249	127,086
11	Customer Accounting	55,527	48,973	55,582	48,931	51,331	43,907
12	Customer Service & Information	105,942	105,520	105,954	105,532	105,997	105,572
13	Sales, Econ Dvlp & Other	44	(6)	45	(5)	45	(5)
14	Administrative & General	282,889	246,966	288,757	252,269	298,218	260,301
15	Total Operating Expenses	$2,633,694	$2,313,678	$2,695,367	$2,365,673	$2,716,040	$2,381,602
16	Depreciation	$780,940	$683,392	$827,574	$719,524	$876,036	$760,859
17	Amortizations	44,375	43,948	43,902	43,475	45,184	44,757
	Taxes:						
18	Property	$201,433	$178,357	$207,317	$183,524	$222,391	$197,091
19	Gross Earnings	0	0	0	0	0	0
20	Deferred Income Tax & ITC	(73,684)	(71,438)	(185,807)	(172,672)	(208,104)	(190,897)
21	Federal & State Income Tax	(8,987)	(6,184)	50,941	59,576	46,802	56,478
22	Payroll & Other	31,385	27,259	31,490	27,352	31,591	27,435
23	Total Taxes	$150,147	$127,994	$103,942	$97,781	$92,680	$90,108
24	**Total Expenses**	$3,609,156	$3,169,012	$3,670,785	$3,226,453	$3,729,940	$3,277,326
25	Allowance for Funds Used During Construction	36,477	28,846	36,630	31,000	38,362	33,500
26	**Total Operating Income**	$627,112	$525,991	$540,845	$445,729	$491,057	$400,352

(1) Revenues and expenses for riders have been included where applicable.

Northern States Power Company
Electric Utility - State of Minnesota
OPERATING INCOME SCHEDULES
STATEMENT OF OPERATING INCOME
($000's)

		Adjusted (1) Most Recent Fiscal Year 2018		Adjusted (1) Projected Fiscal Year 2019	
Line No.	**Description**	**Total Utility (A)**	**Minnesota Jurisdiction (B)**	**Total Utility (C)**	**Minnesota Jurisdiction (D)**
	Operating Revenues				
1	Retail	$3,500,448	$3,088,090	$3,692,521	$3,264,675
2	CIP Revenue Adjustment	0	0	0	0
3	Interdepartmental & Transportation	692	692	464	464
4	Other Operating	763,800	656,690	686,812	580,693
5	Gross Earnings Tax	0	0	0	0
6	**Total Operating Revenues**	$4,264,940	$3,745,473	$4,379,798	$3,845,833
	Expenses				
	Operating Expenses:				
7	Fuel & Purchased Energy	$1,223,523	$1,079,928	$1,112,164	$982,354
8	Power Production	684,243	599,460	675,906	588,266
9	Transmission	276,647	231,048	305,975	253,966
10	Distribution	121,896	108,027	126,009	110,471
11	Customer Accounting	55,787	49,110	54,150	47,821
12	Customer Service & Information	147,368	146,674	134,507	133,837
13	Sales, Econ Dvlp & Other	96	46	63	13
14	Administrative & General	245,614	212,730	243,819	211,324
15	Total Operating Expenses	$2,755,175	$2,427,024	$2,652,593	$2,328,052
16	Depreciation	$656,165	$575,233	$698,277	$608,386
17	Amortizations	68,816	67,177	55,330	54,903
	Taxes:				
18	Property	$208,876	$187,821	$199,217	$176,526
19	Gross Earnings	0	0	0	0
20	Deferred Income Tax & ITC	788	581	(20,712)	(20,260)
21	Federal & State Income Tax	(16,377)	(18,915)	56,590	52,736
22	Payroll & Other	31,417	27,428	31,493	27,341
23	Total Taxes	$224,704	$196,915	$266,588	$236,344
24	**Total Expenses**	$3,704,859	$3,266,350	$3,672,789	$3,227,685
25	Allowance for Funds Used During Construction	34,535	29,731	32,080	24,842
26	**Total Operating Income**	$594,617	$508,854	$739,089	$642,990

(1) Revenues and expenses for riders have been included where applicable.

Northern States Power Company
Electric Utility - State of Minnesota
OPERATING INCOME SCHEDULES
STATEMENT OF OPERATING INCOME
($000's)

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Schedule B-2

Line No.	Description	Unadjusted (1) Proposed Test Year 2020 Total Utility (A)	Unadjusted (1) Proposed Test Year 2020 Minnesota Jurisdiction (B)	Unadjusted (1) Plan Year 2021 Total Utility (C)	Unadjusted (1) Plan Year 2021 Minnesota Jurisdiction (D)	Unadjusted (1) Plan Year 2022 Total Utility (E)	Unadjusted (1) Plan Year 2022 Minnesota Jurisdiction (F)
	Operating Revenues						
1	Retail	$3,637,673	$3,197,649	$3,620,320	$3,183,551	$3,604,411	$3,165,850
2	CIP Revenue Adjustment	0	0	0	0	0	0
3	Interdepartmental & Transportation	494	494	494	494	494	494
4	Other Operating	881,436	765,610	920,378	800,891	947,695	825,186
5	Gross Earnings Tax	0	0	0	0	0	0
6	**Total Operating Revenues**	$4,519,603	$3,963,754	$4,541,193	$3,984,937	$4,552,601	$3,991,531
	Expenses						
	Operating Expenses:						
7	Fuel & Purchased Energy	$1,196,907	$1,062,005	$1,197,316	$1,062,360	$1,196,514	$1,061,665
8	Power Production	647,491	563,360	689,037	599,485	701,958	610,736
9	Transmission	407,648	354,649	414,072	360,238	425,678	370,336
10	Distribution	131,562	114,249	151,911	132,140	146,249	127,086
11	Customer Accounting	55,527	48,973	55,582	48,931	51,331	43,907
12	Customer Service & Information	96,240	95,818	138,978	138,556	145,421	144,996
13	Sales, Econ Dvlp & Other	0	0	0	0	0	0
14	Administrative & General	301,381	262,005	308,661	268,528	319,408	277,657
15	Total Operating Expenses	$2,836,755	$2,501,059	$2,955,557	$2,610,238	$2,986,558	$2,636,383
16	Depreciation	$808,302	$707,973	$890,463	$779,626	$950,476	$832,484
17	Amortizations	34,361	34,361	33,888	33,888	37,139	37,139
			0				
	Taxes:		0				
18	Property	$202,178	$179,102	$210,859	$187,066	$227,775	$202,475
19	Gross Earnings	0	0	0	0	0	0
20	Deferred Income Tax & ITC	(31,974)	(28,495)	(114,476)	(99,396)	(149,275)	(131,615)
21	Federal & State Income Tax	(37,277)	(35,614)	(89,557)	(82,848)	(102,379)	(93,208)
22	Payroll & Other	31,422	27,290	31,527	27,384	31,628	27,468
23	Total Taxes	$164,349	$142,283	$38,353	$32,206	$7,749	$5,119
24	**Total Expenses**	$3,843,766	$3,385,676	$3,918,261	$3,455,958	$3,981,922	$3,511,125
25	Allowance for Funds Used During Construction	36,485	28,853	36,763	31,116	38,375	33,511
26	**Total Operating Income**	$712,322	$606,930	$659,694	$560,095	$609,054	$513,917

(1) Revenues and expenses for riders have been included where applicable.

Northern States Power Company
Electric Utility - State of Minnesota
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		Unadjusted (1) Most Recent Fiscal Year 2018		Unadjusted (1) Projected Fiscal Year 2019	
Line No.	Description	Total Utility (A)	Minnesota Jurisdiction (B)	Total Utility (C)	Minnesota Jurisdiction (D)
	Operating Revenues				
1	Retail	$3,505,179	$3,092,821	$3,703,159	$3,272,609
2	CIP Revenue Adjustment	0	0	0	0
3	Interdepartmental & Transportation	692	692	464	464
4	Other Operating	888,570	777,610	870,022	750,632
5	Gross Earnings Tax	0	0	0	0
6	**Total Operating Revenues**	$4,394,441	$3,871,124	$4,573,646	$4,023,706
	Expenses				
	Operating Expenses:				
7	Fuel & Purchased Energy	$1,270,091	$1,122,180	$1,224,209	$1,080,989
8	Power Production	688,905	603,548	666,795	580,153
9	Transmission	370,361	324,762	400,035	348,026
10	Distribution	121,896	108,027	126,009	110,471
11	Customer Accounting	55,787	49,110	54,150	47,821
12	Customer Service & Information	103,267	102,802	104,698	104,125
13	Sales, Econ Dvlp & Other	0	0	0	0
14	Administrative & General	279,267	243,057	277,706	240,888
15	Total Operating Expenses	$2,889,573	$2,553,485	$2,853,602	$2,512,474
16	Depreciation	$656,165	$575,233	$704,532	$613,831
17	Amortizations	33,535	33,535	40,312	40,312
	Taxes:				
18	Property	$197,827	$176,772	$199,232	$176,541
19	Gross Earnings	0	0	0	0
20	Deferred Income Tax & ITC	5,961	6,716	(24,533)	(23,290)
21	Federal & State Income Tax	(11,862)	(14,198)	53,183	49,803
22	Payroll & Other	31,468	27,477	31,531	27,374
23	Total Taxes	$223,395	$196,767	$259,413	$230,428
24	**Total Expenses**	$3,802,668	$3,359,021	$3,857,859	$3,397,044
25	Allowance for Funds Used During Construction	34,535	29,731	32,955	25,603
26	**Total Operating Income**	$626,308	$541,834	$748,741	$652,264

(1) Revenues and expenses for riders have been included where applicable.

Northern States Power Company
Electric Utility - State of Minnesota
OPERATING INCOME SCHEDULES
COMPUTATION OF FEDERAL AND STATE INCOME TAXES
($000's)

		Adjusted (1) Proposed Test Year 2020		Adjusted (1) Plan Year 2021		Adjusted (1) Plan Year 2022	
Line No.	**Description**	**Total Utility (A)**	**Minnesota Jurisdiction (B)**	**Total Utility (C)**	**Minnesota Jurisdiction (D)**	**Total Utility (E)**	**Minnesota Jurisdiction (F)**
	Income Before Taxes						
1	Total Operating Revenues	$ 4,199,791	$ 3,666,158	$4,175,000	$3,641,182	$ 4,182,634	$ 3,644,178
2	less: Total Operating Expenses	(2,633,694)	(2,313,678)	(2,695,367)	(2,365,673)	(2,716,040)	(2,381,602)
3	Book Depreciation & Amortizatioı	(825,315)	(727,340)	(871,477)	(762,999)	(921,219)	(805,615)
4	Taxes Other Than Income	(159,134)	(134,178)	(53,001)	(38,204)	(45,878)	(33,630)
5	**Total Before Tax Book Income**	**$ 581,648**	**$490,962**	**$ 555,155**	**$ 474,306**	**$499,497**	**$ 423,330**
	Tax Additions						
6	Book Depreciation	$780,940	$683,392	$827,574	$719,524	$876,036	$760,859
7	Nuclear Fuel Book Burn	120,847	105,136	118,156	102,794	123,355	107,318
8	Deferred Income Taxes and ITC	(73,684)	(71,438)	(185,807)	(172,672)	(208,104)	(190,897)
9	Nuclear Outage Amortization	49,687	43,158	48,119	41,788	47,467	41,215
10	Avoided Tax Interest	14,230	10,700	15,120	12,433	17,386	15,172
11	Other Book Additions	6,083	5,656	6,083	5,656	6,083	5,656
12	**Total Tax Additions**	**$898,102**	**$776,603**	**$829,245**	**$709,523**	**$862,222**	**$739,323**
	Tax Deductions						
13	Tax Depreciation and Removal Expense	$1,168,870	$997,042	$1,115,328	$930,357	$1,050,593	$886,793
14	Debt Interest Expense	218,704	187,826	227,352	194,569	240,990	206,901
15	Manufacture Production Deduction	0	0	0	0	0	0
16	Nuclear Outage Amortization	33,725	29,284	62,275	54,072	33,725	29,285
17	Other Tax/Book Timing Differences	11,834	11,855	2,791	3,725	(14,236)	(12,176)
18	NOL Utilized / (Generated)	10,728	0	4,487	0	22,032	0
19	Net Preferred Stock Deduction	0	0	0	0	0	0
20	**Total Tax Deductions**	**$1,443,861**	**$1,226,007**	**$1,412,233**	**$1,182,723**	**$1,333,104**	**$1,110,803**
21	**State Taxable Income**	**$35,889**	**$41,558**	**($27,833)**	**$ 1,106**	**$28,615**	**$51,850**
22	State Income Tax Rate	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%
23	**State Taxes before Credits**	**$3,517**	**$4,073**	**$ (2,728)**	**$108**	**$ 2,804**	**$5,081**
24	State R&E Credit	(1,374)	(1,195)	(1,289)	(1,195)	(1,459)	(1,195)
25	Deferred State Tax Credits Due to NOL	0	0	0	0	0	0
26	**Total State Income Taxes**	**$ 2,143**	**$ 2,877**	**$ (4,017)**	**$ (1,087)**	**$ 1,345**	**$ 3,886**
27	Federal Sec 199 Production Deduction	0	0	0	0	0	0
28	**Federal Taxable Income**	**33,746**	**38,680**	**(23,816)**	**2,193**	**27,270**	**47,964**
29	Federal Income Tax Rate	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
30	**Federal Taxes before Credits**	**$ 7,087**	**$ 8,123**	**$ (5,001)**	**$ 461**	**$ 5,727**	**$ 10,072**
31	Federal Tax Credits	(18,217)	(17,184)	59,959	60,203	39,730	42,520
32	Deferred Federal Tax Credits Due to NOL	0	0	0	0	0	0
33	**Total Federal Income Taxes**	**$ (11,130)**	**$ (9,061)**	**$ 54,957**	**$ 60,663**	**$ 45,457**	**$ 52,592**
34	**Total State and Federal Income Taxes**	**$ (8,987)**	**$ (6,184)**	**$ 50,941**	**$ 59,576**	**$ 46,802**	**$ 56,478**

(1) Revenues and expenses for riders have been included where applicable.

($000's)

Line No.	Description	Adjusted (1) Most Recent Fiscal Year 2018 Total Utility (A)	Adjusted (1) Most Recent Fiscal Year 2018 Minnesota Jurisdiction (B)	Adjusted (1) Projected Fiscal Year 2019 Total Utility (C)	Adjusted (1) Projected Fiscal Year 2019 Minnesota Jurisdiction (D)
	Income Before Taxes				
1	Total Operating Revenues	$ 4,264,940	$ 3,745,473	$ 4,379,798	$ 3,845,833
2	less: Total Operating Expenses	(2,755,175)	(2,427,024)	(2,652,593)	(2,328,052)
3	Book Depreciation & Amortization	(724,980)	(642,411)	(753,607)	(663,289)
4	Taxes Other Than Income	(241,080)	(215,830)	(209,998)	(183,607)
5	**Total Before Tax Book Income**	**$ 543,705**	**$460,209**	**$ 763,599**	**$ 670,884**
	Tax Additions				
6	Book Depreciation	$656,165	$575,233	$698,277	$608,386
7	Nuclear Fuel Book Burn	121,889	106,882	115,692	100,651
8	Deferred Income Taxes and ITC	788	581	(20,712)	(20,260)
9	Nuclear Outage Amortization	53,180	46,510	49,969	43,403
10	Avoided Tax Interest	13,830	11,889	21,854	18,404
11	Other Book Additions	6,083	5,656	6,083	5,656
12	**Total Tax Additions**	**$851,934**	**$746,750**	**$871,163**	**$756,241**
	Tax Deductions				
13	Tax Depreciation and Removal Expense	$829,269	$722,598	$910,641	$794,564
14	Debt Interest Expense	203,013	176,943	208,844	180,404
15	Manufacture Production Deduction	0	0	0	0
16	Nuclear Outage Amortization	34,362	30,053	63,741	55,365
17	Other Tax/Book Timing Differences	26,874	24,904	1,006	(114)
18	NOL Utilized / (Generated)	284,672	254,377	23,637	0
19	Net Preferred Stock Deduction	0	0	0	0
20	**Total Tax Deductions**	**$1,378,190**	**$1,208,876**	**$1,207,870**	**$1,030,220**
21	**State Taxable Income**	**$17,449**	**($1,917)**	**$426,892**	**$ 396,906**
22	State Income Tax Rate	9.80%	9.80%	9.80%	9.80%
23	**State Taxes before Credits**	**$1,710**	**($188)**	**$ 41,835**	**$38,897**
24	State R&E Credit	(3,856)	(3,642)	(1,606)	(1,195)
25	Deferred State Tax Credits Due to NOL	0	0	0	0
26	**Total State Income Taxes**	**$ (2,146)**	**$ (3,830)**	**$ 40,229**	**$ 37,701**
27	Federal Sec 199 Production Deduction	0	0	0	0
28	**Federal Taxable Income**	**19,594**	**1,913**	**386,663**	**359,204**
29	Federal Income Tax Rate	21.00%	21.00%	21.00%	21.00%
30	**Federal Taxes before Credits**	**$ 4,115**	**$ 402**	**$ 81,199**	**$ 75,433**
31	Federal Tax Credits	(18,346)	(15,486)	(64,838)	(60,398)
32	Deferred Federal Tax Credits Due to NOL	0	0	0	0
33	**Total Federal Income Taxes**	**$ (14,231)**	**$ (15,085)**	**$ 16,361**	**$ 15,035**
34	**Total State and Federal Income Taxes**	**$ (16,377)**	**$ (18,915)**	**$ 56,590**	**$ 52,736**

(1) Revenues and expenses for riders have been included where applicable.

Northern States Power Company
Electric Utility - State of Minnesota
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COMPUTATION OF FEDERAL AND STATE INCOME TAXES
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		Unadjusted (1) Proposed Test Year 2020		Unadjusted (1) Plan Year 2021		Unadjusted (1) Plan Year 2022	
Line No.	Description	Total Utility (A)	Minnesota Jurisdiction (B)	Total Utility (C)	Minnesota Jurisdiction (D)	Total Utility (E)	Minnesota Jurisdiction (F)
	Income Before Taxes						
1	Total Operating Revenues	$ 4,519,603	$ 3,963,754	$4,541,193	$3,984,937	$ 4,552,601	$ 3,991,531
2	less: Total Operating Expenses	(2,836,755)	(2,501,059)	(2,955,557)	(2,610,238)	(2,986,558)	(2,636,383)
3	Book Depreciation & Amortizatio	(842,662)	(742,333)	(924,351)	(813,514)	(987,615)	(869,623)
4	Taxes Other Than Income	(201,626)	(177,897)	(127,910)	(115,054)	(110,128)	(98,328)
5	**Total Before Tax Book Income**	**$ 638,560**	**$542,464**	**$ 533,375**	**$ 446,131**	**$468,300**	**$ 387,198**
	Tax Additions						
6	Book Depreciation	$808,302	$707,973	$890,463	$779,626	$950,476	$832,484
7	Nuclear Fuel Book Burn	120,847	105,136	118,156	102,794	123,355	107,318
8	Deferred Income Taxes and ITC	(31,974)	(28,495)	(114,476)	(99,396)	(149,275)	(131,615)
9	Nuclear Outage Amortization	49,687	43,158	48,119	41,788	47,467	41,215
10	Avoided Tax Interest	28,463	24,933	22,747	20,050	17,430	15,215
11	Other Book Additions	0	0	0	0	0	0
12	**Total Tax Additions**	**$975,325**	**$852,703**	**$965,009**	**$844,861**	**$989,453**	**$864,617**
	Tax Deductions						
13	Tax Depreciation and Removal Expense	$1,395,993	$1,218,022	$1,500,043	$1,309,290	$1,349,901	$1,180,766
14	Debt Interest Expense	261,434	226,516	280,238	243,271	291,736	253,746
15	Manufacture Production Deduction	0	0	0	0	0	0
16	Nuclear Outage Amortization	33,725	29,284	62,275	54,072	33,725	29,285
17	Other Tax/Book Timing Differences	11,834	11,855	2,791	3,725	(14,236)	(12,176)
18	NOL Utilized / (Generated)	6,049	0	(35,751)	(31,119)	54,333	31,119
19	Net Preferred Stock Deduction	0	0	0	0	0	0
20	**Total Tax Deductions**	**$1,709,035**	**$1,485,677**	**$1,809,596**	**$1,579,239**	**$1,715,459**	**$1,482,740**
21	**State Taxable Income**	**($95,150)**	**($90,510)**	**($311,212)**	**$ (288,246)**	**($257,706)**	**($230,925)**
22	State Income Tax Rate	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%
23	**State Taxes before Credits**	**($9,325)**	**($8,870)**	**$ (30,499)**	**($28,248)**	**$ (25,255)**	**($22,631)**
24	State R&E Credit	(1,289)	(1,195)	(37)	0	(2,796)	(2,391)
25	Deferred State Tax Credits Due to NOL	0	0	0	0	0	0
26	**Total State Income Taxes**	**$ (10,614)**	**$ (10,065)**	**$ (30,536)**	**$ (28,248)**	**$ (28,051)**	**$ (25,021)**
27	Federal Sec 199 Production Deduction	0	0	0	0	0	0
28	**Federal Taxable Income**	**(84,537)**	**(80,445)**	**(280,676)**	**(259,998)**	**(229,655)**	**(205,904)**
29	Federal Income Tax Rate	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
30	**Federal Taxes before Credits**	**$ (17,753)**	**$ (16,893)**	**$ (58,942)**	**$ (54,600)**	**$ (48,228)**	**$ (43,240)**
31	Federal Tax Credits	(8,911)	(8,655)	(79)	0	(26,101)	(24,947)
32	Deferred Federal Tax Credits Due to NOL	0	0	0	0	0	0
33	**Total Federal Income Taxes**	**$ (26,663)**	**$ (25,548)**	**$ (59,021)**	**$ (54,600)**	**$ (74,328)**	**$ (68,187)**
34	**Total State and Federal Income Taxes**	**$ (37,277)**	**$ (35,614)**	**$ (89,557)**	**$ (82,848)**	**$ (102,379)**	**$ (93,208)**

(1) Revenues and expenses for riders have been included where applicable.

Northern States Power Company
Electric Utility - State of Minnesota
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COMPUTATION OF FEDERAL AND STATE INCOME TAXES
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		Unadjusted (1) Most Recent Fiscal Year 2018		Unadjusted (1) Projected Fiscal Year 2019	
Line No.	Description	Total Utility (A)	Minnesota Jurisdiction (B)	Total Utility (C)	Minnesota Jurisdiction (D)
	Income Before Taxes				
1	Total Operating Revenues	$ 4,394,441	$ 3,871,124	$ 4,573,646	$ 4,023,706
2	less: Total Operating Expenses	(2,889,573)	(2,553,485)	(2,853,602)	(2,512,474)
3	Book Depreciation & Amortization	(689,700)	(608,769)	(744,844)	(654,143)
4	Taxes Other Than Income	(235,257)	(210,965)	(206,230)	(180,625)
5	**Total Before Tax Book Income**	**$ 579,911**	**$497,905**	**$ 768,970**	**$ 676,464**
	Tax Additions				
6	Book Depreciation	$656,165	$575,233	$704,532	$613,831
7	Nuclear Fuel Book Burn	121,889	106,882	115,692	100,651
8	Deferred Income Taxes and ITC	5,961	6,716	(24,533)	(23,290)
9	Nuclear Outage Amortization	53,180	46,510	49,969	43,403
10	Avoided Tax Interest	14,155	12,215	26,799	23,276
11	Other Book Additions	0	0	0	0
12	**Total Tax Additions**	**$851,350**	**$747,556**	**$872,458**	**$757,871**
	Tax Deductions				
13	Tax Depreciation and Removal Expense	$829,269	$722,598	$935,464	$816,209
14	Debt Interest Expense	213,688	186,391	234,370	202,896
15	Manufacture Production Deduction	0	0	0	0
16	Nuclear Outage Amortization	34,362	30,053	63,741	55,365
17	Other Tax/Book Timing Differences	26,874	24,904	1,006	(114)
18	NOL Utilized / (Generated)	281,991	254,377	20,226	0
19	Net Preferred Stock Deduction	0	0	0	0
20	**Total Tax Deductions**	**$1,386,184**	**$1,218,323**	**$1,254,808**	**$1,074,356**
21	**State Taxable Income**	**$45,077**	**$27,137**	**$386,620**	**$ 359,979**
22	State Income Tax Rate	9.80%	9.80%	9.80%	9.80%
23	**State Taxes before Credits**	**$4,418**	**$2,659**	**$ 37,889**	**$35,278**
24	State R&E Credit	(3,856)	(3,642)	(1,606)	(1,195)
25	Deferred State Tax Credits Due to NOL	0	0	0	0
26	**Total State Income Taxes**	**$ 562**	**$ (983)**	**$ 36,283**	**$ 34,083**
27	Federal Sec 199 Production Deduction	0	0	0	0
28	**Federal Taxable Income**	**44,515**	**28,120**	**350,338**	**325,896**
29	Federal Income Tax Rate	21.00%	21.00%	21.00%	21.00%
30	**Federal Taxes before Credits**	**$ 9,348**	**$ 5,905**	**$ 73,571**	**$ 68,438**
31	Federal Tax Credits	(21,772)	(19,120)	(56,670)	(52,718)
32	Deferred Federal Tax Credits Due to NOL	0	0	0	0
33	**Total Federal Income Taxes**	**$ (12,424)**	**$ (13,215)**	**$ 16,901**	**$ 15,720**
34	**Total State and Federal Income Taxes**	**$ (11,862)**	**$ (14,198)**	**$ 53,183**	**$ 49,803**

(1) Revenues and expenses for riders have been included where applicable.

($000's)

		Adjusted (1) Proposed Test Year 2020		Adjusted (1) Plan Year 2021		Adjusted (1) Plan Year 2022	
Line No.	Description	Total Utility (A)	Minnesota Jurisdiction (B)	Total Utility (C)	Minnesota Jurisdiction (D)	Total Utility (E)	Minnesota Jurisdiction (F)
	Provision for Deferred Income Taxes from Liberalized Depreciation						
1	Production	$29,165	$19,002	$10,684	($1,566)	($30,854)	($34,263)
2	Transmission	12,500	10,867	10,801	9,283	9,540	8,075
3	Distribution	(10,317)	(9,277)	(8,169)	(7,202)	(3,866)	(3,253)
4	General	(2,489)	(2,342)	(1,624)	(1,690)	(2,131)	(1,998)
5	Common	(544)	(473)	(2,092)	(1,822)	(48)	(42)
6	Net Operating Loss (NOL)	(106,868)	(93,712)	(197,908)	(172,039)	(178,729)	(157,543)
7	Amortizations	0	0	0	0	0	0
8	Non-Plant Related	6,234	5,719	3,868	3,587	(651)	(651)
9	TOTAL Deferred Income Taxes	($72,319)	($70,215)	($184,441)	($171,449)	($206,739)	($189,674)

(1) Revenues and expenses for riders have been included where applicable.

Northern States Power Company
Electric Utility - State of Minnesota
OPERATING INCOME SCHEDULES
COMPUTATION OF DEFERRED INCOME TAXES
($000's)

Line No.	Description	Adjusted (1) Most Recent Fiscal Year 2018 Total Utility (A)	Adjusted (1) Most Recent Fiscal Year 2018 Minnesota Jurisdiction (B)	Adjusted (1) Projected Fiscal Year 2019 Total Utility (C)	Adjusted (1) Projected Fiscal Year 2019 Minnesota Jurisdiction (D)
	Provision for Deferred Income Taxes from Liberalized Depreciation				
1	Production	($34,084)	($30,042)	($13,258)	($11,857)
2	Transmission	21,270	18,682	14,114	$12,268
3	Distribution	(18,217)	(17,546)	(11,318)	(9,527)
4	General	(3,999)	(3,500)	(4,982)	(4,350)
5	Common	1,076	942	1,770	1,541
6	Net Operating Loss (NOL)	25,842	24,048	(8,702)	(9,326)
7	Amortizations	0	0	0	0
8	Non-Plant Related	10,265	9,229	3,029	2,213
9	TOTAL Deferred Income Taxes	$2,154	$1,811	($19,347)	($19,037)

(1) Revenues and expenses for riders have been included where applicable.

Northern States Power Company
Electric Utility - State of Minnesota
OPERATING INCOME SCHEDULES
COMPUTATION OF DEFERRED INCOME TAXES
($000's)

		Unadjusted (1) Proposed Test Year 2020		Unadjusted (1) Plan Year 2021		Unadjusted (1) Plan Year 2022	
Line No.	Description	Total Utility (A)	Minnesota Jurisdiction (B)	Total Utility (C)	Minnesota Jurisdiction (D)	Total Utility (E)	Minnesota Jurisdiction (F)
	Provision for Deferred Income Taxes from Liberalized Depreciation						
1	Production	$81,513	$70,404	$97,525	$84,434	$30,960	$26,842
2	Transmission	12,463	10,831	11,689	10,172	11,367	9,901
3	Distribution	(10,317)	(9,277)	(8,169)	(7,202)	(3,866)	(3,253)
4	General	(1,140)	(993)	520	453	(1,031)	(897)
5	Common	(544)	(473)	(2,092)	(1,822)	(48)	(42)
6	Net Operating Loss (NOL)	(118,818)	(103,482)	(216,451)	(187,794)	(184,642)	(162,293)
7	Amortizations	0	0	0	0	0	0
8	Non-Plant Related	6,234	5,719	3,868	3,587	(651)	(651)
9	TOTAL Deferred Income Taxes	($30,608)	($27,272)	($113,110)	($98,173)	($147,910)	($130,393)

(1) Revenues and expenses for riders have been included where applicable.

Northern States Power Company
Electric Utility - State of Minnesota
OPERATING INCOME SCHEDULES
COMPUTATION OF DEFERRED INCOME TAXES
($000's)

Line No.	Description	Unadjusted (1) Most Recent Fiscal Year 2018 Total Utility (A)	Unadjusted (1) Most Recent Fiscal Year 2018 Minnesota Jurisdiction (B)	Unadjusted (1) Projected Fiscal Year 2019 Total Utility (C)	Unadjusted (1) Projected Fiscal Year 2019 Minnesota Jurisdiction (D)
	Provision for Deferred Income Taxes from Liberalized Depreciation				
1	Production	($32,724)	($28,682)	($8,011)	($7,267)
2	Transmission	21,270	18,682	14,076	12,230
3	Distribution	(18,217)	(17,546)	(11,318)	(9,527)
4	General	(3,999)	(3,500)	(4,884)	(4,252)
5	Common	1,076	942	1,770	1,541
6	Net Operating Loss (NOL)	28,514	27,682	(17,830)	(17,006)
7	Amortizations	0	0	0	0
8	Non-Plant Related	11,407	10,371	3,029	2,213
9	TOTAL Deferred Income Taxes	$7,327	$7,947	($23,168)	($22,067)

(1) Revenues and expenses for riders have been included where applicable.

Let: F=Federal Income Tax = 21.00%
M=Minnesota State Income Tax Rate = 9.80%
D=North Dakota State Income Tax Rate = 4.31%
S=South Dakota State Income Tax Rate = 0%
N=Net Income After Interest Deductions but Before Income Taxes

Jurisdictional:

Only Minnesota and Federal Income Taxes

M=	9.80%	(N)
F=	18.94%	(N)
M+F=	28.74%	(N)

Only North Dakota and Federal Income Taxes

D=	4.31%	(N)
F=	20.09%	(N)
D+F=	24.40%	(N)

Only South Dakota and Federal Income Taxes

S=	0.00%	(N)
F=	21.00%	(N)
S+F=	21.00%	(N)

Composite:

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

M + D + S + F 28.11% (N)

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

Northern States Power Company

INCOME STATEMENT SCHEDULES
INCOME STATEMENT ADJUSTMENT SCHEDULES
2020 Unadjusted Test Year versus 2020 Adjusted Test Year
($000's)

1	2	3	4		5	6	7	8	9	10	11	12	13	14	15	16
	Work Paper Reference						WP-A1 - A15	WP-A16	WP-A17	WP-A18	WP-A19 - A21	WP-A22 - A23	WP-A24	WP-A25	WP-A26	WP-A27
			Unadjusted Secondary Calcs			Base	Precedential	Adjustment								
Line No.	Description	Unadjusted	ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Final Unadjusted	Precedential Adjustments	CIP Approved Program Levels	CIP Incentive	IA ROE	Incentive Compensation	Mankato Energy as PPA	Pension: Active Healthcare	Pension: Deferred Amort	Pension: Discount Rate	Pension: Non Qualified
1																
2	Operating Revenues															
3	Retail Revenue	3,197,649				3,197,649		(15,496)								
4	Interdepartmental	494				494										
5	Other Operating	765,610				765,610	14,021		15,033	(8,285)		(4,590)				
6	Total Revenue	3,963,753				3,963,753	14,021	(15,496)	15,033	(8,285)		(4,590)				
7																
8	Expenses															
9	Operating Expenses															
10	Fuel & Purchased Energy	1,062,005				1,062,005										
11	Power Production	573,931				573,931	(16)			(5,434)	(3,728)	50,713				
12	Transmission	344,079				344,079										
13	Distribution	114,249				114,249										
14	Customer Accounting	48,973				48,973										
15	Customer Service and Information	95,818				95,818		(15,496)	25,373							
16	Sales, Econ Dev, & Other						(6)									
17	Administrative and General	262,005				262,005	(5,474)				(11,527)		(1,524)	5,882	66	(875)
18	Total Operating Expenses	2,501,059				2,501,059	(5,495)	(15,496)	25,373	(5,434)	(15,255)	50,713	(1,524)	5,882	66	(875)
19																
20	Depreciation	707,973				707,973						(18,606)				
21	Amortization	34,361				34,361										
22																
23	Taxes															
24	Property	179,102				179,102										
25	Deferred Income Tax and ITC	74,987			(103,482)	(28,495)						(6,335)				
26	Federal and State Income Tax	(138,396)	(122)	840	102,066	(35,614)	5,618	(0)	(2,972)	(819)	4,385	(539)	438	(1,690)	(19)	252
27	Payroll and Other	27,290				27,290	(32)									
28	Total Taxes	142,983	(122)	840	(1,416)	142,283	5,587	(0)	(2,972)	(819)	4,385	(6,874)	438	(1,690)	(19)	252
29																
30	Total Expenses	3,386,376	(122)	840	(1,416)	3,385,676	91	(15,496)	22,401	(6,253)	(10,871)	25,232	(1,086)	4,191	47	(624)
31																
32	Allowance for Funds Used During Construction	28,853				28,853						(7)				
33																
34	Total Operating Income	606,231	122	(840)	1,416	606,930	13,930	(0)	(7,368)	(2,032)	10,871	(29,829)	1,086	(4,191)	(47)	624
35																
36	Calculation of Revenue Requirements															
37	Rate Base	9,959,257	18,918	(129,815)	219,022	10,067,382						(547,556)				
38	Required Operating Income	705,115	1,339	(9,191)	15,507	712,771						(38,767)				
39	Operating Income	606,231	122	(840)	1,416	606,930	13,930	(0)	(7,368)	(2,032)	10,871	(29,829)	1,086	(4,191)	(47)	624
40	Income Deficiency	98,884	1,217	(8,351)	14,090	105,840	(13,930)	0	7,368	2,032	(10,871)	(8,938)	(1,086)	4,191	47	(624)
41	**Revenue Deficiency**	**138,770**	**1,708**	**(11,720)**	**19,774**	**148,531**	**(19,548)**	**0**	**10,340**	**2,851**	**(15,255)**	**(12,543)**	**(1,524)**	**5,882**	**66**	**(875)**
42																
43	Calculation of Income Taxes															
44	Operating Revenue	3,963,753				3,963,753	14,021	(15,496)	15,033	(8,285)		(4,590)				
45	-Operating Expense	2,501,059				2,501,059	(5,495)	(15,496)	25,373	(5,434)	(15,255)	50,713	(1,524)	5,882	66	(875)
46	-Amortization	34,361				34,361										
47	-Taxes Other then Income	281,379			(103,482)	177,897	(32)					(6,335)				
48	Operating Income Before Adjs	1,146,954			103,482	1,250,436	19,548	(0)	(10,340)	(2,851)	15,255	(48,968)	1,524	(5,882)	(66)	875
49	Additions to Income	248,212			(103,482)	144,730						(6,339)				
50	Deductions from Income	1,259,160				1,259,160						(41,111)				
51	Debt Synchonization	224,083	426	(2,921)	4,928	226,516						(12,320)				
52	State Taxable Income	(88,077)	(426)	2,921	(4,928)	(90,510)	19,548	(0)	(10,340)	(2,851)	15,255	(1,876)	1,524	(5,882)	(66)	875
53	State Income Tax Before Credits	(8,632)	(42)	286	(483)	(8,870)	1,916	(0)	(1,013)	(279)	1,495	(184)	149	(576)	(6)	86
54	State Tax Credits	(1,195)				(1,195)										
55	Federal Tax Deductions															
56	Federal Taxable Income	(78,250)	(384)	2,635	(4,445)	(80,445)	17,632	(0)	(9,327)	(2,572)	13,760	(1,692)	1,375	(5,305)	(59)	790
57	Federal Income Tax Before Credits	(16,433)	(81)	553	(933)	(16,893)	3,703	(0)	(1,959)	(540)	2,890	(355)	289	(1,114)	(12)	166
58	Federal Tax Credits	(112,137)			103,482	(8,655)										
59	Total Income Taxes	(138,396)	(122)	840	102,066	(35,614)	5,618	(0)	(2,972)	(819)	4,385	(539)	438	(1,690)	(19)	252

($000's)

1	2	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
	Work Paper Reference	WP-A28	WP-A29	WP-A30	WP-A31	WP-A32	WP-A33	WP-A34	WP-A35	WP-A36	WP-A37	WP-A38	WP-A39	WP-A40	WP-A41	WP-A42
							Amortizations						Rider Removals			
Line No.	Description	Pension: Retiree Medical	Trading: Asset-Based Margin	Trading: Non Asset-Based Admin	Trading: Non Asset-Based Margin	Transmission ROE	Aurora	LED Street Lighting	NOL ADIT ARAM	PI EPU Recovery	Rate Case Expenses	Sherco 3 Depr Deferral	Renewable Connect	Rider: RES	Rider: TCR	Windsource
1																
2	Operating Revenues															
3	Retail Revenue													(56,514)	(4,994)	
4	Interdepartmental															
5	Other Operating		(108,280)		(13,649)	(15,963)				1,750					(90,249)	(10,381)
6	Total Revenue		(108,280)		(13,649)	(15,963)				1,750				(56,514)	(95,243)	(10,381)
7																
8	Expenses															
9	Operating Expenses															
10	Fuel & Purchased Energy		(103,457)		(6,918)								(6,395)			(7,605)
11	Power Production												1,339	(2,037)	(250)	779
12	Transmission					(10,346)									(88,683)	
13	Distribution															
14	Customer Accounting															
15	Customer Service and Information												(25)			(150)
16	Sales, Econ Dev, & Other															
17	Administrative and General	207		(1,793)												
18	Total Operating Expenses	207	(103,457)	(1,793)	(6,918)	(10,346)							(5,081)	(2,037)	(88,933)	(6,976)
19																
20	Depreciation													(3,879)	(2,095)	
21	Amortization						1,970	168	2,269	2,884	1,794	503				
22																
23	Taxes															
24	Property													(706)	(39)	
25	Deferred Income Tax and ITC									(1,179)		(205)		(43,761)	(1,233)	
26	Federal and State Income Tax	(60)	(1,386)	515	(1,934)	(1,614)	(576)	(51)	(301)	351	(516)	(28)	1,460	35,094	339	(979)
27	Payroll and Other															
28	Total Taxes	(60)	(1,386)	515	(1,934)	(1,614)	(576)	(51)	(301)	(828)	(516)	(233)	1,460	(9,373)	(933)	(979)
29																
30	Total Expenses	148	(104,844)	(1,278)	(8,853)	(11,960)	1,394	117	1,968	2,056	1,278	270	(3,621)	(15,289)	(91,961)	(7,955)
31																
32	Allowance for Funds Used During Construction															
33																
34	Total Operating Income	(148)	(3,437)	1,278	(4,796)	(4,002)	(1,394)	(117)	(1,968)	(305)	(1,278)	(270)	3,621	(41,225)	(3,281)	(2,426)
35																
36	Calculation of Revenue Requirements															
37	Rate Base						1,488	419	46,509	23,587		4,319		(549,960)	(43,772)	
38	Required Operating Income						105	30	3,293	1,670		306		(38,937)	(3,099)	
39	Operating Income	(148)	(3,437)	1,278	(4,796)	(4,002)	(1,394)	(117)	(1,968)	(305)	(1,278)	(270)	3,621	(41,225)	(3,281)	(2,426)
40	Income Deficiency	148	3,437	(1,278)	4,796	4,002	1,499	146	5,261	1,975	1,278	576	(3,621)	2,288	182	2,426
41	**Revenue Deficiency**	**207**	**4,823**	**(1,793)**	**6,730**	**5,616**	**2,104**	**206**	**7,383**	**2,772**	**1,794**	**808**	**(5,081)**	**3,211**	**256**	**3,405**
42																
43	Calculation of Income Taxes															
44	Operating Revenue		(108,280)		(13,649)	(15,963)				1,750				(56,514)	(95,243)	(10,381)
45	-Operating Expense	207	(103,457)	(1,793)	(6,918)	(10,346)							(5,081)	(2,037)	(88,933)	(6,976)
46	-Amortization						1,970	168	2,269	2,884	1,794	503				
47	-Taxes Other then Income									(1,179)		(205)		(44,467)	(1,272)	
48	Operating Income Before Adjs	(207)	(4,823)	1,793	(6,730)	(5,616)	(1,970)	(168)	(2,269)	45	(1,794)	(298)	5,081	(10,011)	(5,038)	(3,405)
49	Additions to Income								2,269	1,705		298		(57,579)	(1,644)	
50	Deductions from Income													(172,995)	(6,874)	
51	Debt Synchonization						33	9	1,046	531		97		(12,374)	(985)	
52	State Taxable Income	(207)	(4,823)	1,793	(6,730)	(5,616)	(2,003)	(177)	(1,046)	1,220	(1,794)	(97)	5,081	117,780	1,178	(3,405)
53	State Income Tax Before Credits	(20)	(473)	176	(660)	(550)	(196)	(17)	(103)	120	(176)	(10)	498	11,542	115	(334)
54	State Tax Credits															
55	Federal Tax Deductions															
56	Federal Taxable Income	(187)	(4,350)	1,617	(6,071)	(5,066)	(1,807)	(160)	(944)	1,100	(1,618)	(88)	4,583	106,237	1,062	(3,071)
57	Federal Income Tax Before Credits	(39)	(914)	340	(1,275)	(1,064)	(379)	(34)	(198)	231	(340)	(18)	962	22,310	223	(645)
58	Federal Tax Credits													1,241		
59	Total Income Taxes	(60)	(1,386)	515	(1,934)	(1,614)	(576)	(51)	(301)	351	(516)	(28)	1,460	35,094	339	(979)

INCOME STATEMENT SCHEDULES
INCOME STATEMENT ADJUSTMENT SCHEDULES
2020 Unadjusted Test Year versus 2020 Adjusted Test Ye
($000's)

1	2	32	33	34	35	36	37	38
	Work Paper Reference	WP-A43	WP-A44	WP-A46	WP-A45			
		Secondary Calculations					Fuel Adjustment	
Line No.	Description	ADIT Prorate for IRS	Cash Working Capital	Change in Cost of Capital	Net Operating Loss	Total	Remove FCA Revenue and Fuel Expense	Total Net of Fuel
1								
2	Operating Revenues							
3	Retail Revenue					3,120,645	(796,055)	2,324,590
4	Interdepartmental					494		494
5	Other Operating					545,018		545,018
6	Total Revenue					3,666,158	(796,055)	2,870,103
7								
8	Expenses							
9	Operating Expenses							
10	Fuel & Purchased Energy					937,629	(796,055)	141,574
11	Power Production					615,297		615,297
12	Transmission					245,050		245,050
13	Distribution					114,249		114,249
14	Customer Accounting					48,973		48,973
15	Customer Service and Information					105,520		105,520
16	Sales, Econ Dev, & Other					(6)		(6)
17	Administrative and General					246,966		246,966
18	Total Operating Expenses					2,313,678	(796,055)	1,517,623
19								
20	Depreciation					683,392		683,392
21	Amortization					43,948		43,948
22								
23	Taxes							
24	Property					178,357		178,357
25	Deferred Income Tax and ITC				9,770	(71,438)		(71,438)
26	Federal and State Income Tax	88	(69)	4,133	(9,689)	(6,184)		(6,184)
27	Payroll and Other					27,259		27,259
28	Total Taxes	88	(69)	4,133	81	127,994		127,994
29								
30	Total Expenses	88	(69)	4,133	81	3,169,012	(796,055)	2,372,957
31								
32	Allowance for Funds Used During Construction					28,846		28,846
33								
34	Total Operating Income	(88)	69	(4,133)	(81)	525,991		525,991
35								
36	Calculation of Revenue Requirements							
37	Rate Base	(13,615)	10,666		(12,565)	8,986,901		8,986,901
38	Required Operating Income	(964)	755	33,252	(890)	669,524		669,524
39	Operating Income	(88)	69	(4,133)	(81)	525,991		525,991
40	Income Deficiency	(876)	686	37,384	(808)	143,533		143,533
41	**Revenue Deficiency**	**(1,229)**	**963**	**52,463**	**(1,134)**	**201,427**		**201,427**
42								
43	Calculation of Income Taxes							
44	Operating Revenue					3,666,158		3,666,158
45	-Operating Expense					2,313,678		2,313,678
46	-Amortization					43,948		43,948
47	-Taxes Other then Income				9,770	134,178		134,178
48	Operating Income Before Adjs				(9,770)	1,174,354		1,174,354
49	Additions to Income				9,770	93,211		93,211
50	Deductions from Income					1,038,181		1,038,181
51	Debt Synchonization	(306)	240	(14,379)	(283)	187,826		187,826
52	State Taxable Income	306	(240)	14,379	283	41,558		41,558
53	State Income Tax Before Credits	30	(24)	1,409	28	4,073		4,073
54	State Tax Credits					(1,195)		(1,195)
55	Federal Tax Deductions							
56	Federal Taxable Income	276	(216)	12,970	255	38,680		38,680
57	Federal Income Tax Before Credits	58	(45)	2,724	54	8,123		8,123
58	Federal Tax Credits				(9,770)	(17,184)		(17,184)
59	Total Income Taxes	88	(69)	4,133	(9,689)	(6,184)		(6,184)

INCOME STATEMENT SCHEDULES
INCOME STATEMENT ADJUSTMENT SCHEDULES
2021 Unadjusted Test Year versus 2021 Adjusted Test Year
($000's)

1	2	3	4		5	6	7	8	9	10	11	12	13	14	15	16
	Work Paper Reference						WP-A1 - A15	WP-A16	WP-A17	WP-A18	WP-A19 - A21	WP-A22 - A23	WP-A24	WP-A25	WP-A26	WP-A27
			Unadjusted Secondary Calcs			Base	Precedential	Adjustment								
Line No.	Description	Unadjusted	ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Final Unadjusted	Precedential Adjustments	CIP Approved Program Levels	CIP Incentive	IA ROE	Incentive Compensation	Mankato Energy as PPA	Pension: Active Healthcare	Pension: Deferred Amort	Pension: Discount Rate	Pension: Non Qualified
1																
2	Operating Revenues															
3	Retail Revenue	3,183,551				3,183,551		(46,844)								
4	Interdepartmental	494				494										
5	Other Operating	800,891				800,891	12,822		3,654	(9,521)		(4,045)				
6	Total Revenue	3,984,937				3,984,937	12,822	(46,844)	3,654	(9,521)		(4,045)				
7																
8	Expenses															
9	Operating Expenses															
10	Fuel & Purchased Energy	1,062,360				1,062,360										
11	Power Production	610,060				610,060	(16)			(5,641)	(3,867)	51,979				
12	Transmission	349,663				349,663										
13	Distribution	132,140				132,140										
14	Customer Accounting	48,931				48,931										
15	Customer Service and Information	138,556				138,556		(46,844)	13,994							
16	Sales, Econ Dev, & Other						(5)									
17	Administrative and General	268,528				268,528	(5,595)				(12,315)		(1,904)	5,882	66	(817)
18	Total Operating Expenses	2,610,238				2,610,238	(5,616)	(46,844)	13,994	(5,641)	(16,182)	51,979	(1,904)	5,882	66	(817)
19																
20	Depreciation	779,626				779,626						(18,650)				
21	Amortization	33,888				33,888										
22																
23	Taxes															
24	Property	187,066				187,066										
25	Deferred Income Tax and ITC	88,399			(187,794)	(99,396)						(5,633)				
26	Federal and State Income Tax	(267,987)	(149)	902	184,387	(82,848)	5,309	(0)	(2,972)	(1,115)	4,651	(1,601)	547	(1,690)	(19)	235
27	Payroll and Other	27,384				27,384	(32)									
28	Total Taxes	34,861	(149)	902	(3,407)	32,206	5,277	(0)	(2,972)	(1,115)	4,651	(7,234)	547	(1,690)	(19)	235
29																
30	Total Expenses	3,458,613	(149)	902	(3,407)	3,455,958	(340)	(46,844)	11,022	(6,756)	(11,531)	26,095	(1,357)	4,191	47	(582)
31																
32	Allowance for Funds Used During Construction	31,116				31,116						(115)				
33																
34	Total Operating Income	557,440	149	(902)	3,407	560,095	13,162	(0)	(7,368)	(2,765)	11,531	(30,255)	1,357	(4,191)	(47)	582
35																
36	Calculation of Revenue Requirements															
37	Rate Base	10,411,119	23,090	(139,445)	517,285	10,812,048						(526,198)				
38	Required Operating Income	737,107	1,635	(9,873)	36,624	765,493						(37,255)				
39	Operating Income	557,440	149	(902)	3,407	560,095	13,162	(0)	(7,368)	(2,765)	11,531	(30,255)	1,357	(4,191)	(47)	582
40	Income Deficiency	179,667	1,485	(8,971)	33,217	205,398	(13,162)	0	7,368	2,765	(11,531)	(6,999)	(1,357)	4,191	47	(582)
41	**Revenue Deficiency**	**252,137**	**2,085**	**(12,589)**	**46,614**	**288,246**	**(18,471)**	**0**	**10,340**	**3,880**	**(16,182)**	**(9,823)**	**(1,904)**	**5,882**	**66**	**(817)**
42																
43	Calculation of Income Taxes															
44	Operating Revenue	3,984,937				3,984,937	12,822	(46,844)	3,654	(9,521)		(4,045)				
45	-Operating Expense	2,610,238				2,610,238	(5,616)	(46,844)	13,994	(5,641)	(16,182)	51,979	(1,904)	5,882	66	(817)
46	-Amortization	33,888				33,888										
47	-Taxes Other then Income	302,848			(187,794)	115,054	(32)					(5,633)				
48	Operating Income Before Adjs	1,037,962			187,794	1,225,757	18,471	(0)	(10,340)	(3,880)	16,182	(50,391)	1,904	(5,882)	(66)	817
49	Additions to Income	253,030			(187,794)	65,236						(5,706)				
50	Deductions from Income	1,367,087			(31,119)	1,335,968						(38,687)				
51	Debt Synchonization	234,250	520	(3,138)	11,639	243,271						(11,839)				
52	State Taxable Income	(310,344)	(520)	3,138	19,480	(288,246)	18,471	(0)	(10,340)	(3,880)	16,182	(5,571)	1,904	(5,882)	(66)	817
53	State Income Tax Before Credits	(30,414)	(51)	307	1,909	(28,248)	1,810	(0)	(1,013)	(380)	1,586	(546)	187	(576)	(6)	80
54	State Tax Credits	(1,195)			1,195											
55	Federal Tax Deductions															
56	Federal Taxable Income	(278,735)	(469)	2,830	16,376	(259,998)	16,661	(0)	(9,327)	(3,499)	14,596	(5,025)	1,718	(5,305)	(59)	737
57	Federal Income Tax Before Credits	(58,534)	(98)	594	3,439	(54,600)	3,499	(0)	(1,959)	(735)	3,065	(1,055)	361	(1,114)	(12)	155
58	Federal Tax Credits	(177,844)			177,844											
59	Total Income Taxes	(267,987)	(149)	902	184,387	(82,848)	5,309	(0)	(2,972)	(1,115)	4,651	(1,601)	547	(1,690)	(19)	235

Northern States Power Company

Docket No. E002/GR-19-564
Financial Information
Schedule D

INCOME STATEMENT SCHEDULES
INCOME STATEMENT ADJUSTMENT SCHEDULES
2021 Unadjusted Test Year versus 2021 Adjusted Test Ye:
($000's)

1	2	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
	Work Paper Reference	WP-A28	WP-A29	WP-A30	WP-A31	WP-A32	WP-A33	WP-A34	WP-A35	WP-A36	WP-A37	WP-A38	WP-A39	WP-A40	WP-A41	WP-A42
							Amortizations						Rider Removals			
Line No.	Description	Pension: Retiree Medical	Trading: Asset-Based Margin	Trading: Non Asset-Based Admin	Trading: Non Asset-Based Margin	Transmission ROE	Aurora	LED Street Lighting	NOL ADIT ARAM	PI EPU Recovery	Rate Case Expenses	Sherco 3 Depr Deferral	Renewable Connect	Rider: RES	Rider: TCR	Windsource
1																
2	Operating Revenues															
3	Retail Revenue													(52,116)	(4,142)	
4	Interdepartmental															
5	Other Operating		(108,280)		(13,649)	(16,336)				1,622					(96,541)	(10,381)
6	Total Revenue		(108,280)		(13,649)	(16,336)				1,622				(52,116)	(100,683)	(10,381)
7																
8	Expenses															
9	Operating Expenses															
10	Fuel & Purchased Energy		(103,457)		(6,918)								(6,395)			(7,605)
11	Power Production												1,364	(15,102)	(429)	779
12	Transmission					(9,611)									(90,355)	
13	Distribution															
14	Customer Accounting															
15	Customer Service and Information												(25)			(150)
16	Sales, Econ Dev, & Other															
17	Administrative and General	206		(1,781)												
18	Total Operating Expenses	206	(103,457)	(1,781)	(6,918)	(9,611)							(5,056)	(15,102)	(90,784)	(6,976)
19																
20	Depreciation													(38,437)	(3,015)	
21	Amortization						1,970	168	2,269	2,884	1,794	503				
22																
23	Taxes															
24	Property													(2,977)	(564)	
25	Deferred Income Tax and ITC									(1,179)		(205)		(79,576)	(2,438)	
26	Federal and State Income Tax	(59)	(1,386)	512	(1,934)	(1,933)	(569)	(50)	(286)	325	(516)	(26)	1,453	154,591	1,099	(979)
27	Payroll and Other															
28	Total Taxes	(59)	(1,386)	512	(1,934)	(1,933)	(569)	(50)	(286)	(854)	(516)	(231)	1,453	72,038	(1,904)	(979)
29																
30	Total Expenses	147	(104,844)	(1,269)	(8,853)	(11,544)	1,400	118	1,983	2,030	1,278	272	(3,603)	18,499	(95,703)	(7,955)
31																
32	Allowance for Funds Used During Construction															
33																
34	Total Operating Income	(147)	(3,437)	1,269	(4,796)	(4,792)	(1,400)	(118)	(1,983)	(408)	(1,278)	(272)	3,603	(70,615)	(4,979)	(2,426)
35																
36	Calculation of Revenue Requirements															
37	Rate Base						492	252	44,240	21,882		4,021		(942,039)	(66,423)	
38	Required Operating Income						35	18	3,132	1,549		285		(66,696)	(4,703)	
39	Operating Income	(147)	(3,437)	1,269	(4,796)	(4,792)	(1,400)	(118)	(1,983)	(408)	(1,278)	(272)	3,603	(70,615)	(4,979)	(2,426)
40	Income Deficiency	147	3,437	(1,269)	4,796	4,792	1,435	136	5,115	1,957	1,278	557	(3,603)	3,919	276	2,426
41	**Revenue Deficiency**	**206**	**4,823**	**(1,781)**	**6,730**	**6,724**	**2,014**	**190**	**7,178**	**2,746**	**1,794**	**781**	**(5,056)**	**5,499**	**388**	**3,405**
42																
43	Calculation of Income Taxes															
44	Operating Revenue		(108,280)		(13,649)	(16,336)				1,622				(52,116)	(100,683)	(10,381)
45	-Operating Expense	206	(103,457)	(1,781)	(6,918)	(9,611)							(5,056)	(15,102)	(90,784)	(6,976)
46	-Amortization						1,970	168	2,269	2,884	1,794	503				
47	-Taxes Other then Income									(1,179)		(205)		(82,553)	(3,003)	
48	Operating Income Before Adjs	(206)	(4,823)	1,781	(6,730)	(6,724)	(1,970)	(168)	(2,269)	(83)	(1,794)	(298)	5,056	45,539	(6,896)	(3,405)
49	Additions to Income								2,269	1,705		298		(85,778)	(3,780)	
50	Deductions from Income													(327,244)	(13,003)	
51	Debt Synchonization						11	6	995	492		90		(21,196)	(1,495)	
52	State Taxable Income	(206)	(4,823)	1,781	(6,730)	(6,724)	(1,981)	(173)	(995)	1,130	(1,794)	(90)	5,056	308,200	3,822	(3,405)
53	State Income Tax Before Credits	(20)	(473)	175	(660)	(659)	(194)	(17)	(98)	111	(176)	(9)	495	30,204	375	(334)
54	State Tax Credits															
55	Federal Tax Deductions															
56	Federal Taxable Income	(186)	(4,350)	1,607	(6,071)	(6,065)	(1,787)	(156)	(898)	1,019	(1,618)	(82)	4,561	277,997	3,448	(3,071)
57	Federal Income Tax Before Credits	(39)	(914)	337	(1,275)	(1,274)	(375)	(33)	(189)	214	(340)	(17)	958	58,379	724	(645)
58	Federal Tax Credits													66,008		
59	Total Income Taxes	(59)	(1,386)	512	(1,934)	(1,933)	(569)	(50)	(286)	325	(516)	(26)	1,453	154,591	1,099	(979)

INCOME STATEMENT SCHEDULES
INCOME STATEMENT ADJUSTMENT SCHEDULES
2021 Unadjusted Test Year versus 2021 Adjusted Test Ye
($000's)

1	2	32	33	34	35	36	37	38
	Work Paper Reference	WP-A43	WP-A44	WP-A46	WP-A45			
		Secondary Calculations					Fuel Adjustment	
Line No.	Description	ADIT Prorate for IRS	Cash Working Capital	Change in Cost of Capital	Net Operating Loss	Total	Remove FCA Revenue and Fuel Expense	Total Net of Fuel
1								
2	Operating Revenues							
3	Retail Revenue					3,080,450	(796,055)	2,284,395
4	Interdepartmental					494		494
5	Other Operating					560,238		560,238
6	Total Revenue					3,641,181	(796,055)	2,845,126
7								
8	Expenses							
9	Operating Expenses							
10	Fuel & Purchased Energy					937,984	(796,055)	141,929
11	Power Production					639,126		639,126
12	Transmission					249,696		249,696
13	Distribution					132,140		132,140
14	Customer Accounting					48,931		48,931
15	Customer Service and Information					105,532		105,532
16	Sales, Econ Dev, & Other					(5)		(5)
17	Administrative and General					252,269		252,269
18	Total Operating Expenses					2,365,673	(796,055)	1,569,618
19								
20	Depreciation					719,524		719,524
21	Amortization					43,475		43,475
22								
23	Taxes							
24	Property					183,524		183,524
25	Deferred Income Tax and ITC				15,756	(172,672)		(172,672)
26	Federal and State Income Tax	152	(80)	4,281	(15,515)	59,576		59,576
27	Payroll and Other					27,352		27,352
28	Total Taxes	152	(80)	4,281	241	97,780		97,780
29								
30	Total Expenses	152	(80)	4,281	241	3,226,452	(796,055)	2,430,397
31								
32	Allowance for Funds Used During Construction					31,000		31,000
33								
34	Total Operating Income	(152)	80	(4,281)	(240)	445,730		445,730
35								
36	Calculation of Revenue Requirements							
37	Rate Base	(23,467)	12,415		(27,678)	9,309,544		9,309,544
38	Required Operating Income	(1,661)	879	34,445	(1,960)	693,561		693,561
39	Operating Income	(152)	80	(4,281)	(240)	445,730		445,730
40	Income Deficiency	(1,510)	799	38,727	(1,720)	247,831		247,831
41	**Revenue Deficiency**	**(2,119)**	**1,121**	**54,347**	**(2,413)**	**347,794**		**347,794**
42								
43	Calculation of Income Taxes							
44	Operating Revenue					3,641,181	(796,055)	2,845,126
45	-Operating Expense					2,365,673	(796,055)	1,569,618
46	-Amortization					43,475		43,475
47	-Taxes Other then Income				15,756	38,204		38,204
48	Operating Income Before Adjs				(15,756)	1,193,829		1,193,829
49	Additions to Income				15,756	(10,001)		(10,001)
50	Deductions from Income				31,119	988,153		988,153
51	Debt Synchonization	(528)	279	(14,895)	(623)	194,569		194,569
52	State Taxable Income	528	(279)	14,895	(30,496)	1,105		1,105
53	State Income Tax Before Credits	52	(27)	1,460	(2,989)	108		108
54	State Tax Credits				(1,195)	(1,195)		(1,195)
55	Federal Tax Deductions							
56	Federal Taxable Income	476	(252)	13,436	(26,312)	2,192		2,192
57	Federal Income Tax Before Credits	100	(53)	2,821	(5,526)	460		460
58	Federal Tax Credits				(5,805)	60,203		60,203
59	Total Income Taxes	152	(80)	4,281	(15,515)	59,576		59,576

Northern States Power Company

INCOME STATEMENT SCHEDULES
INCOME STATEMENT ADJUSTMENT SCHEDULES
2022 Unadjusted Test Year versus 2022 Adjusted Test Year
($000's)

1	2	3	4		5	6	7	8	9	10	11	12	13	14	15	16
	Work Paper Reference						WP-A1 - A15	WP-A16	WP-A17	WP-A18	WP-A19 - A21	WP-A22 - A23	WP-A24	WP-A25	WP-A26	WP-A27
			Unadjusted Secondary Calcs			Base	Precedential	Adjustment								
Line No.	Description	Unadjusted	ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Final Unadjusted	Precedential Adjustments	CIP Approved Program Levels	CIP Incentive	IA ROE	Incentive Compensation	Mankato Energy as PPA	Pension: Active Healthcare	Pension: Deferred Amort	Pension: Discount Rate	Pension: Non Qualified
1																
2	Operating Revenues															
3	Retail Revenue	3,165,850				3,165,850		(49,589)								
4	Interdepartmental	494				494										
5	Other Operating	825,186				825,186	12,213			(9,963)		(3,648)				
6	Total Revenue	3,991,531				3,991,531	12,213	(49,589)		(9,963)		(3,648)				
7																
8	Expenses															
9	Operating Expenses															
10	Fuel & Purchased Energy	1,061,665				1,061,665										
11	Power Production	621,400				621,400				(5,923)	(4,086)	52,945				
12	Transmission	359,672				359,672										
13	Distribution	127,086				127,086										
14	Customer Accounting	43,907				43,907										
15	Customer Service and Information	144,996				144,996		(49,589)	10,340							
16	Sales, Econ Dev, & Other						(5)									
17	Administrative and General	277,657				277,657	(5,645)				(12,959)		(2,335)	5,882	66	(748)
18	Total Operating Expenses	2,636,383				2,636,383	(5,650)	(49,589)	10,340	(5,923)	(17,046)	52,945	(2,335)	5,882	66	(748)
19																
20	Depreciation	832,484				832,484						(18,840)				
21	Amortization	37,139				37,139										
22																
23	Taxes															
24	Property	202,475				202,475										
25	Deferred Income Tax and ITC	30,677			(162,293)	(131,615)						(4,748)				
26	Federal and State Income Tax	(252,058)	(56)	999	157,892	(93,208)	5,143		(2,972)	(1,161)	4,899	(2,736)	671	(1,690)	(19)	215
27	Payroll and Other	27,468				27,468	(32)									
28	Total Taxes	8,562	(56)	999	(4,400)	5,119	5,111		(2,972)	(1,161)	4,899	(7,484)	671	(1,690)	(19)	215
29																
30	Total Expenses	3,514,567	(56)	999	(4,400)	3,511,125	(539)	(49,589)	7,368	(7,084)	(12,146)	26,621	(1,664)	4,191	47	(533)
31																
32	Allowance for Funds Used During Construction	33,511				33,511						(11)				
33																
34	Total Operating Income	510,475	56	(999)	4,400	513,917	12,752		(7,368)	(2,879)	12,146	(30,280)	1,664	(4,191)	(47)	533
35																
36	Calculation of Revenue Requirements															
37	Rate Base	10,735,676	8,736	(154,456)	687,629	11,277,585						(505,827)				
38	Required Operating Income	760,086	619	(10,935)	48,684	798,453						(35,813)				
39	Operating Income	510,475	56	(999)	4,400	513,917	12,752		(7,368)	(2,879)	12,146	(30,280)	1,664	(4,191)	(47)	533
40	Income Deficiency	249,611	562	(9,937)	44,284	284,536	(12,752)		7,368	2,879	(12,146)	(5,533)	(1,664)	4,191	47	(533)
41	**Revenue Deficiency**	**350,292**	**789**	**(13,945)**	**62,146**	**399,304**	**(17,895)**		**10,340**	**4,040**	**(17,046)**	**(7,764)**	**(2,335)**	**5,882**	**66**	**(748)**
42																
43	Calculation of Income Taxes															
44	Operating Revenue	3,991,531				3,991,531	12,213	(49,589)		(9,963)		(3,648)				
45	-Operating Expense	2,636,383				2,636,383	(5,650)	(49,589)	10,340	(5,923)	(17,046)	52,945	(2,335)	5,882	66	(748)
46	-Amortization	37,139				37,139										
47	-Taxes Other then Income	260,620			(162,293)	98,328	(32)					(4,748)				
48	Operating Income Before Adjs	1,057,389			162,293	1,219,682	17,895		(10,340)	(4,040)	17,046	(51,845)	2,335	(5,882)	(66)	748
49	Additions to Income	194,426			(162,293)	32,133						(4,755)				
50	Deductions from Income	1,197,875			31,119	1,228,994						(35,701)				
51	Debt Synchonization	241,553	197	(3,475)	15,525	253,746						(11,381)				
52	State Taxable Income	(187,613)	(197)	3,475	(46,644)	(230,925)	17,895		(10,340)	(4,040)	17,046	(9,518)	2,335	(5,882)	(66)	748
53	State Income Tax Before Credits	(18,386)	(19)	341	(4,571)	(22,631)	1,754		(1,013)	(396)	1,670	(933)	229	(576)	(6)	73
54	State Tax Credits	(1,195)			(1,195)	(2,391)										
55	Federal Tax Deductions															
56	Federal Taxable Income	(168,032)	(177)	3,135	(40,877)	(205,904)	16,142		(9,327)	(3,644)	15,375	(8,585)	2,107	(5,305)	(59)	675
57	Federal Income Tax Before Credits	(35,287)	(37)	658	(8,584)	(43,240)	3,390		(1,959)	(765)	3,229	(1,803)	442	(1,114)	(12)	142
58	Federal Tax Credits	(197,190)			172,243	(24,947)										
59	Total Income Taxes	(252,058)	(56)	999	157,892	(93,208)	5,143		(2,972)	(1,161)	4,899	(2,736)	671	(1,690)	(19)	215

Northern States Power Company

INCOME STATEMENT SCHEDULES
INCOME STATEMENT ADJUSTMENT SCHEDULES
2022 Unadjusted Test Year versus 2022 Adjusted Test Ye
($000's)

1	2	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
	Work Paper Reference	WP-A28	WP-A29	WP-A30	WP-A31	WP-A32	WP-A33	WP-A34	WP-A35	WP-A36	WP-A37	WP-A38	WP-A39	WP-A40	WP-A41	WP-A42
							Amortizations						Rider Removals			
Line No.	Description	Pension: Retiree Medical	Trading: Asset-Based Margin	Trading: Non Asset-Based Admin	Trading: Non Asset-Based Margin	Transmission ROE	Aurora	LED Street Lighting	NOL ADIT ARAM	PI EPU Recovery	Rate Case Expenses	Sherco 3 Depr Deferral	Renewable Connect	Rider: RES	Rider: TCR	Windsource
1																
2	Operating Revenues															
3	Retail Revenue													(44,519)	(2,799)	
4	Interdepartmental															
5	Other Operating		(108,280)		(13,649)	(16,870)				1,494					(101,366)	(10,381)
6	Total Revenue		(108,280)		(13,649)	(16,870)				1,494				(44,519)	(104,165)	(10,381)
7																
8	Expenses															
9	Operating Expenses															
10	Fuel & Purchased Energy		(103,457)		(6,918)								(6,395)			(7,605)
11	Power Production												3,863	(20,119)	(430)	779
12	Transmission					(9,580)									(91,069)	
13	Distribution															
14	Customer Accounting															
15	Customer Service and Information												(25)			(150)
16	Sales, Econ Dev, & Other															
17	Administrative and General	206		(1,820)												
18	Total Operating Expenses	206	(103,457)	(1,820)	(6,918)	(9,580)							(2,558)	(20,119)	(91,499)	(6,976)
19																
20	Depreciation													(48,577)	(4,208)	
21	Amortization							168	2,269	2,884	1,794	503				
22																
23	Taxes															
24	Property													(4,072)	(1,312)	
25	Deferred Income Tax and ITC									(1,179)		(205)		(55,791)	(2,108)	
26	Federal and State Income Tax	(59)	(1,386)	523	(1,934)	(2,095)		(49)	(271)	299	(516)	(24)	735	153,141	576	(979)
27	Payroll and Other															
28	Total Taxes	(59)	(1,386)	523	(1,934)	(2,095)		(49)	(271)	(880)	(516)	(229)	735	93,277	(2,843)	(979)
29																
30	Total Expenses	147	(104,844)	(1,297)	(8,853)	(11,675)		119	1,997	2,004	1,278	274	(1,822)	24,581	(98,550)	(7,955)
31																
32	Allowance for Funds Used During Construction															
33																
34	Total Operating Income	(147)	(3,437)	1,297	(4,796)	(5,195)		(119)	(1,997)	(510)	(1,278)	(274)	1,822	(69,100)	(5,616)	(2,426)
35																
36	Calculation of Revenue Requirements															
37	Rate Base							84	41,972	20,177		3,723		(920,073)	(74,773)	
38	Required Operating Income							6	2,972	1,429		264		(65,141)	(5,294)	
39	Operating Income	(147)	(3,437)	1,297	(4,796)	(5,195)		(119)	(1,997)	(510)	(1,278)	(274)	1,822	(69,100)	(5,616)	(2,426)
40	Income Deficiency	147	3,437	(1,297)	4,796	5,195		125	4,969	1,939	1,278	537	(1,822)	3,959	322	2,426
41	**Revenue Deficiency**	**206**	**4,823**	**(1,820)**	**6,730**	**7,290**		**175**	**6,973**	**2,721**	**1,794**	**754**	**(2,558)**	**5,555**	**451**	**3,405**
42																
43	Calculation of Income Taxes															
44	Operating Revenue		(108,280)		(13,649)	(16,870)				1,494				(44,519)	(104,165)	(10,381)
45	-Operating Expense	206	(103,457)	(1,820)	(6,918)	(9,580)							(2,558)	(20,119)	(91,499)	(6,976)
46	-Amortization							168	2,269	2,884	1,794	503				
47	-Taxes Other then Income									(1,179)		(205)		(59,863)	(3,420)	
48	Operating Income Before Adjs	(206)	(4,823)	1,820	(6,730)	(7,290)		(168)	(2,269)	(211)	(1,794)	(298)	2,558	35,464	(9,247)	(3,405)
49	Additions to Income								2,269	1,705		298		(55,827)	(2,109)	
50	Deductions from Income													(246,593)	(11,679)	
51	Debt Synchonization							2	944	454		84		(20,702)	(1,682)	
52	State Taxable Income	(206)	(4,823)	1,820	(6,730)	(7,290)		(170)	(944)	1,040	(1,794)	(84)	2,558	246,932	2,006	(3,405)
53	State Income Tax Before Credits	(20)	(473)	178	(660)	(714)		(17)	(93)	102	(176)	(8)	251	24,199	197	(334)
54	State Tax Credits															
55	Federal Tax Deductions															
56	Federal Taxable Income	(186)	(4,350)	1,642	(6,071)	(6,575)		(153)	(852)	938	(1,618)	(76)	2,307	222,732	1,809	(3,071)
57	Federal Income Tax Before Credits	(39)	(914)	345	(1,275)	(1,381)		(32)	(179)	197	(340)	(16)	484	46,774	380	(645)
58	Federal Tax Credits													82,168		
59	Total Income Taxes	(59)	(1,386)	523	(1,934)	(2,095)		(49)	(271)	299	(516)	(24)	735	153,141	576	(979)

INCOME STATEMENT SCHEDULES
INCOME STATEMENT ADJUSTMENT SCHEDULES
2022 Unadjusted Test Year versus 2022 Adjusted Test Ye
($000's)

1	2	32	33	34	35	36	37	38
	Work Paper Reference	WP-A43	WP-A44	WP-A46	WP-A45			
		Secondary Calculations					Fuel Adjustment	
Line No.	Description	ADIT Prorate for IRS	Cash Working Capital	Change in Cost of Capital	Net Operating Loss	Total	Remove FCA Revenue and Fuel Expense	Total Net of Fuel
1								
2	Operating Revenues							
3	Retail Revenue					3,068,944	(796,055)	2,272,889
4	Interdepartmental					494		494
5	Other Operating					574,739		574,739
6	Total Revenue					3,644,177	(796,055)	2,848,122
7								
8	Expenses							
9	Operating Expenses							
10	Fuel & Purchased Energy					937,289	(796,055)	141,234
11	Power Production					648,428		648,428
12	Transmission					259,023		259,023
13	Distribution					127,086		127,086
14	Customer Accounting					43,907		43,907
15	Customer Service and Information					105,572		105,572
16	Sales, Econ Dev, & Other					(5)		(5)
17	Administrative and General					260,301		260,301
18	Total Operating Expenses					2,381,602	(796,055)	1,585,547
19								
20	Depreciation					760,859		760,859
21	Amortization					44,757		44,757
22								
23	Taxes							
24	Property					197,091		197,091
25	Deferred Income Tax and ITC				4,750	(190,897)		(190,897)
26	Federal and State Income Tax	113	(88)	3,946	(4,596)	56,478		56,478
27	Payroll and Other					27,435		27,435
28	Total Taxes	113	(88)	3,946	154	90,108		90,108
29								
30	Total Expenses	113	(88)	3,946	154	3,277,326	(796,055)	2,481,271
31								
32	Allowance for Funds Used During Construction					33,500		33,500
33								
34	Total Operating Income	(113)	88	(3,946)	(154)	400,352		400,352
35								
36	Calculation of Revenue Requirements							
37	Rate Base	(17,463)	13,568		(33,232)	9,805,740		9,805,740
38	Required Operating Income	(1,236)	961	38,242	(2,353)	732,489		732,489
39	Operating Income	(113)	88	(3,946)	(154)	400,352		400,352
40	Income Deficiency	(1,123)	873	42,188	(2,199)	332,137		332,137
41	**Revenue Deficiency**	**(1,577)**	**1,225**	**59,205**	**(3,086)**	**466,104**		**466,104**
42								
43	Calculation of Income Taxes							
44	Operating Revenue					3,644,177		3,644,177
45	-Operating Expense					2,381,602		2,381,602
46	-Amortization					44,757		44,757
47	-Taxes Other then Income				4,750	33,630		33,630
48	Operating Income Before Adjs				(4,750)	1,184,189		1,184,189
49	Additions to Income				4,750	(21,536)		(21,536)
50	Deductions from Income				(31,119)	903,902		903,902
51	Debt Synchonization	(393)	305	(13,728)	(748)	206,901		206,901
52	State Taxable Income	393	(305)	13,728	31,867	51,850		51,850
53	State Income Tax Before Credits	39	(30)	1,345	3,123	5,081		5,081
54	State Tax Credits				1,195	(1,195)		(1,195)
55	Federal Tax Deductions							
56	Federal Taxable Income	354	(275)	12,383	27,549	47,964		47,964
57	Federal Income Tax Before Credits	74	(58)	2,600	5,785	10,072		10,072
58	Federal Tax Credits				(14,701)	42,520		42,520
59	Total Income Taxes	113	(88)	3,946	(4,597)	56,478		56,478

Adjustment Type	Adjustment	Adjustment Description
Precedential Adjustments	Precedential Adjustments	Combination of all precedential adjustments with consistent rate case treatment
Rate Case Adjustments	CIP Approved Program Levels	Brings CIP revenues and expenses to approved program levels
Rate Case Adjustments	CIP Incentive	Removes the CIP performace incentive revenues
Rate Case Adjustments	IA ROE	Reduce the Interchange rate of return on common equity from 11.47 percent to 10.4 percent
Rate Case Adjustments	Incentive Compensation	Removal of AIP over 20% of base salary and long term incentive; inclusion of LTI related to environmental goals
Rate Case Adjustments	Mankato Energy as PPA	Removes capital and O&M for MEC and adds cost of MEC I and II PPA
Rate Case Adjustments	Pension: Active Healthcare	This adjustment changes the per-book amounts to reflect the actual incurred claim amounts during the period
Rate Case Adjustments	Pension: Deferred Amort	Three-year amortization of the XES Plan cap cumulative deferred balance
Rate Case Adjustments	Pension: Discount Rate	This adjustment a recalculation of MYRP Forecast pension costs to capture the most current pension position and to provide an update to all elements of cost.
Rate Case Adjustments	Pension: Non Qualified	Removes all non-qualified pension expenses related to the Company's Supplemental Executive Retirement Plan (SERP) and Restoration Plan
Rate Case Adjustments	Pension: Retiree Medical	An adjustment to reflect the use of the five-year average discount rate to calculate retiree medical benefits
Rate Case Adjustments	Trading: Asset-Based Margin	Remove asset based trading fuel costs and revenue from test and plan years
Rate Case Adjustments	Trading: Non Asset-Based Admin	Remove non-asset based administration costs from recovery
Rate Case Adjustments	Trading: Non Asset-Based Margin	Remove non-asset based trading fuel costs and revenue from test and plan years
Rate Case Adjustments	Transmission ROE	An adjustment to calculate the net transmission revenue credit using the last authorized ROE of 9.06 percent
Rate Case Adjustments - amortizations	Aurora	Reflects the Aurora deferral requested in 2020-2022 MYRP
Rate Case Adjustments - amortizations	LED Street Lighting	Reflects the LED Street Lighting deferral requested in 2020-2022 MYRP
Rate Case Adjustments - amortizations	NOL ADIT ARAM	Reflects the amorization level per Commission's Order in Docket No. E,G-999/CI-17-895 in the 2020-2022 MYRP
Rate Case Adjustments - amortizations	PI EPU Recovery	Reflects the PI EPU costs deferred in Docket No. E002/GR-13-868 in the 2020-2022 MYRP
Rate Case Adjustments - amortizations	Rate Case Expenses	Three year amortization of costs related to rate case
Rate Case Adjustments - amortizations	Sherco 3 Depr Deferral	Reflects the Sherco 3 costs deferred in Docket No. E002/GR-13-868 in the 2020-2022 MYRP
Rider Removal	Renewable Connect	Removal of expenses related to Renewable*Connect rider; inclusion of capacity credit
Rider Removal	Rider: RES	Removes revenue and expense that will continue to be collected through the RES rider
Rider Removal	Rider: TCR	Removes revenue and expense that will continue to be collected through the TCR rider
Rider Removal	Windsource	Removal of expenses related to Windsource rider; inclusion of capacity credit

Northern States Power Company

Docket No. E002/GR-19-564
Financial Information
Schedule D - 2019 Projected

INCOME STATEMENT SCHEDULES
INCOME STATEMENT ADJUSTMENT SCHEDULES
2019 Unadjusted Projected Year versus 2019 Projected Year
($000's)

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
			Base				Precedential							Amortizations		
Line No.	Description	Unadjusted	ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Total Unadjusted	Precedential Adjustments	CIP Incentive	Incentive Compensation	Mankato Energy	Trading: Asset-Based Margin	Trading: Non Asset-Based Admin	Trading: Non Asset-Based Margin	Aurora	LED Street Lighting	NOL ADIT ARAM
1																
2	Operating Revenues															
3	Retail Revenue	3,273,024				3,273,024										
4	Interdepartmental	464				464										
5	Other Operating	750,632				750,632	13,132	14,635		(3,106)	(47,137)		(37,579)		(193)	
6	Total Revenue	4,024,121				4,024,121	13,132	14,635		(3,106)	(47,137)		(37,579)		(193)	
7																
8	Expenses															
9	Operating Expenses															
10	Fuel & Purchased Energy	1,080,989				1,080,989					(44,002)		(43,381)			
11	Power Production	590,093				590,093	(69)		(5,274)	12,020						
12	Transmission	338,087				338,087										
13	Distribution	110,471				110,471										
14	Customer Accounting	47,821				47,821										
15	Customer Service and Information	104,125				104,125		29,887								
16	Sales, Econ Dev, & Other	0				0	13									
17	Administrative and General	240,888				240,888	(5,920)		(22,053)			(1,591)				
18	Total Operating Expenses	2,512,474				2,512,474	(5,975)	29,887	(27,328)	12,020	(44,002)	(1,591)	(43,381)			
19																
20	Depreciation	613,831				613,831				(5,419)						
21	Amortization	49,247				49,247										2,269
22																
23	Taxes															
24	Property	176,541				176,541										
25	Deferred Income Tax and ITC	(6,284)			(17,006)	(23,290)				(4,399)						
26	Federal and State Income Tax	29,528	13	863	16,951	47,354	5,501	(4,384)	7,854	3,438	(901)	457	1,667	(10)	(57)	(315)
27	Payroll and Other	27,374				27,374	(33)									
28	Total Taxes	227,158	13	863	(55)	227,979	5,468	(4,384)	7,854	(961)	(901)	457	1,667	(10)	(57)	(315)
29																
30	Total Expenses	3,402,710	13	863	(55)	3,403,531	(507)	25,503	(19,473)	5,640	(44,903)	(1,134)	(41,713)	(10)	(57)	1,953
31																
32	Allowance for Funds Used During Construction	25,603				25,603				(761)						
33																
34	Total Operating Income	647,014	(13)	(863)	55	646,193	13,639	(10,868)	19,473	(9,506)	(2,234)	1,134	4,134	10	(136)	(1,953)
35																
36	Calculation of Revenue Requirements															
37	Rate Base	9,144,553	(1,950)	(133,489)	8,503	9,017,617				(280,236)				1,603	252	48,778
38	Required Operating Income	647,434	(138)	(9,451)	602	638,447				(19,841)				113	18	3,453
39	Operating Income	647,014	(13)	(863)	55	646,193	13,639	(10,868)	19,473	(9,506)	(2,234)	1,134	4,134	10	(136)	(1,953)
40	Income Deficiency	420	(125)	(8,588)	547	(7,746)	(13,639)	10,868	(19,473)	(10,335)	2,234	(1,134)	(4,134)	103	153	5,407
41	**Revenue Deficiency**	**590**	**(176)**	**(12,052)**	**768**	**(10,870)**	**(19,140)**	**15,251**	**(27,328)**	**(14,503)**	**3,135**	**(1,591)**	**(5,801)**	**145**	**215**	**7,588**
42																
43	Calculation of Income Taxes															
44	Operating Revenue	4,024,121				4,024,121	13,132	14,635		(3,106)	(47,137)		(37,579)		(193)	
45	-Operating Expense	2,512,474				2,512,474	(5,975)	29,887	(27,328)	12,020	(44,002)	(1,591)	(43,381)			
46	-Amortization	49,247				49,247										2,269
47	-Taxes Other then Income	197,630			(17,006)	180,625	(33)			(4,399)						
48	Operating Income Before Adjs	1,264,770			17,006	1,281,775	19,140	(15,251)	27,328	(10,726)	(3,135)	1,591	5,801		(193)	(2,269)
49	Additions to Income	161,046			(17,006)	144,040				(4,886)						2,269
50	Deductions from Income	871,460				871,460				(21,269)						
51	Debt Synchonization	205,752	(44)	(3,003)	191	202,896				(6,305)				36	6	1,098
52	State Taxable Income	348,603	44	3,003	(191)	351,459	19,140	(15,251)	27,328	11,961	(3,135)	1,591	5,801	(36)	(198)	(1,098)
53	State Income Tax Before Credits	34,163	4	294	(19)	34,443	1,876	(1,495)	2,678	1,172	(307)	156	569	(4)	(19)	(108)
54	State Tax Credits	(1,195)				(1,195)										
55	Federal Tax Deductions															
56	Federal Taxable Income	315,636	40	2,709	(173)	318,212	17,264	(13,757)	24,649	10,789	(2,828)	1,435	5,233	(33)	(179)	(990)
57	Federal Income Tax Before Credits	66,283	8	569	(36)	66,824	3,625	(2,889)	5,176	2,266	(594)	301	1,099	(7)	(38)	(208)
58	Federal Tax Credits	(69,724)			17,006	(52,718)										
59	Total Income Taxes	29,528	13	863	16,951	47,354	5,501	(4,384)	7,854	3,438	(901)	457	1,667	(10)	(57)	(315)

Northern States Power Company

INCOME STATEMENT SCHEDULES
INCOME STATEMENT ADJUSTMENT SCHEDULES
2019 Unadjusted Projected Year versus 2019 Projected Y
($000's)

1	2	18	19	20	21	22	23	24	25	26	27	28
				Rider Removal								
Line No.	Description	PI EPU Recovery	Sherco 3 Depr Deferral	Renewable Connect	Rider: RES	Rider: TCR	Windsource	ADIT Prorate for IRS	Cash Working Capital	Change in Cost of Capital	Net Operating Loss	Total
1												
2	Operating Revenues											
3	Retail Revenue				(12,613)	4,264						3,264,675
4	Interdepartmental											464
5	Other Operating	1,889				(100,743)	(10,837)					580,693
6	Total Revenue	1,889			(12,613)	(96,479)	(10,837)					3,845,833
7												
8	Expenses											
9	Operating Expenses											
10	Fuel & Purchased Energy			(3,279)			(7,975)					982,354
11	Power Production			779		(121)	779					598,206
12	Transmission					(94,060)						244,027
13	Distribution											110,471
14	Customer Accounting											47,821
15	Customer Service and Information			(25)			(150)					133,837
16	Sales, Econ Dev, & Other											13
17	Administrative and General											211,324
18	Total Operating Expenses			(2,525)		(94,181)	(7,346)					2,328,052
19												
20	Depreciation				(1)	(25)						608,386
21	Amortization	2,884	503									54,903
22												
23	Taxes											
24	Property				(15)							176,526
25	Deferred Income Tax and ITC	(1,179)	(205)		1,230	(97)					7,680	(20,260)
26	Federal and State Income Tax	379	(30)	726	(4,037)	(402)	(1,004)	8	(92)	4,238	(7,655)	52,736
27	Payroll and Other											27,341
28	Total Taxes	(800)	(235)	726	(2,822)	(499)	(1,004)	8	(92)	4,238	25	236,344
29												
30	Total Expenses	2,084	268	(1,799)	(2,822)	(94,705)	(8,349)	8	(92)	4,238	25	3,227,685
31												
32	Allowance for Funds Used During Construction											24,842
33												
34	Total Operating Income	(195)	(268)	1,799	(9,790)	(1,775)	(2,488)	(8)	92	(4,238)	(25)	642,990
35												
36	Calculation of Revenue Requirements											
37	Rate Base	25,292	4,616		(130,209)	(23,603)		(1,259)	14,272		(3,840)	8,673,282
38	Required Operating Income	1,791	327		(9,219)	(1,671)		(89)	1,010	33,826	(272)	647,894
39	Operating Income	(195)	(268)	1,799	(9,790)	(1,775)	(2,488)	(8)	92	(4,238)	(25)	642,990
40	Income Deficiency	1,986	595	(1,799)	571	104	2,488	(81)	918	38,064	(247)	4,904
41	**Revenue Deficiency**	**2,787**	**835**	**(2,525)**	**802**	**145**	**3,492**	**(114)**	**1,288**	**53,417**	**(347)**	**6,883**
42												
43	Calculation of Income Taxes											
44	Operating Revenue	1,889			(12,613)	(96,479)	(10,837)					3,845,833
45	-Operating Expense			(2,525)		(94,181)	(7,346)					2,328,052
46	-Amortization	2,884	503									54,903
47	-Taxes Other then Income	(1,179)	(205)		1,215	(97)					7,680	183,607
48	Operating Income Before Adjs	184	(298)	2,525	(13,828)	(2,202)	(3,492)				(7,680)	1,279,270
49	Additions to Income	1,705	298		(3,149)	(102)					7,680	147,855
50	Deductions from Income				(2)	(374)						849,815
51	Debt Synchonization	569	104		(2,930)	(531)		(28)	321	(14,745)	(86)	180,404
52	State Taxable Income	1,320	(104)	2,525	(14,045)	(1,399)	(3,492)	28	(321)	14,745	86	396,906
53	State Income Tax Before Credits	129	(10)	247	(1,376)	(137)	(342)	3	(31)	1,445	8	38,897
54	State Tax Credits											(1,195)
55	Federal Tax Deductions											
56	Federal Taxable Income	1,191	(94)	2,277	(12,668)	(1,262)	(3,150)	26	(290)	13,300	78	359,204
57	Federal Income Tax Before Credits	250	(20)	478	(2,660)	(265)	(661)	5	(61)	2,793	16	75,433
58	Federal Tax Credits										(7,680)	(60,398)
59	Total Income Taxes	379	(30)	726	(4,037)	(402)	(1,004)	8	(92)	4,238	(7,655)	52,736
				(1,142)					(1,179)		(272)	

Adjustment Type	Adjustment	Adjustment Description
Adjustment	Precedential Adjustments	Combination of all precedential adjustments with consistent rate case treatment
Adjustment	CIP Incentive	Removes the CIP performace incentive revenues
Adjustment	Incentive Compensation	Removal of AIP over 15% of base salary and long term incentive
Adjustment	Mankato Energy	Removes capital and O&M for MEC and adds cost of MEC I and II PPA
Adjustment	Trading: Asset-Based Margin	Remove asset based trading fuel costs and revenue from test and plan years
Adjustment	Trading: Non Asset-Based Admin	Remove non-asset based administration costs from recovery
Adjustment	Trading: Non Asset-Based Margin	Remove non-asset based trading fuel costs and revenue from test and plan years
Rate Case Adjustments - amortizations	Aurora	Reflects the Aurora deferral requested in 2020-2022 MYRP
Rate Case Adjustments - amortizations	LED Street Lighting	Reflects the LED Street Lighting deferral requested in 2020-2022 MYRP
Rate Case Adjustments - amortizations	NOL ADIT ARAM	Reflects the amorization level per Commission's Order in Docket No. E,G-999/CI-17-895 in the 2020-2022 MYRP
Rate Case Adjustments - amortizations	PI EPU Recovery	Reflects the PI EPU costs deferred in Docket No. E002/GR-13-868 in the 2020-2022 MYRP
Rate Case Adjustments - amortizations	Sherco 3 Depr Deferral	Reflects the Sherco 3 costs deferred in Docket No. E002/GR-13-868 in the 2020-2022 MYRP
Rider Removal	Renewable Connect	Removal of expenses related to Renewable*Connect rider; inclusion of capacity credit
Rider Removal	Rider: RES	Removes revenue and expense that will continue to be collected through the RES rider
Rider Removal	Rider: TCR	Removes revenue and expense that will continue to be collected through the TCR rider
Rider Removal	Windsource	Removal of expenses related to Windsource rider; inclusion of capacity credit

Northern States Power Company

Docket No. E002/GR-19-564
Financial Information
Schedule D - 2018

INCOME STATEMENT SCHEDULES
INCOME STATEMENT ADJUSTMENT SCHEDULES
2018 Unadjusted Actual Year versus 2018 Adjusted Actual Year
($000's)

1	2	3	4		5	6	7	8	9	10	11	12	13	14	15	16
		Base														
Line No.	Description	Unadjusted	Cash Working Capital	Net Operating Loss	Total Unadjusted	Advertising	Aviation	Customer Deposits Expense	Dues: Chamber of Commerce	Dues: Professional Associations	Economic Development Admin	Economic Development Donations	Employee Expenses	Foundation and Other Donations	Incentive Compensation	Investor Relations
1																
2	Operating Revenues															
3	Retail Revenue	3,092,821			3,092,821											
4	Interdepartmental	692			692											
5	Other Operating	777,610			777,610											
6	Total Revenue	3,871,124			3,871,124											
7																
8	Expenses															
9	Operating Expenses															
10	Fuel & Purchased Energy	1,122,180			1,122,180											
11	Power Production	613,027			613,027										(3,970)	
12	Transmission	315,282			315,282											
13	Distribution	108,027			108,027											
14	Customer Accounting	49,110			49,110											
15	Customer Service and Information	102,802			102,802	(1)										
16	Sales, Econ Dev, & Other	0			0						(33)	79				
17	Administrative and General	243,057			243,057	(3,372)	(2,131)	19	150	(133)			(1,613)	1,440	(17,283)	(324)
18	Total Operating Expenses	2,553,485			2,553,485	(3,372)	(2,131)	19	150	(133)	(33)	79	(1,613)	1,440	(21,252)	(324)
19																
20	Depreciation	575,233			575,233											
21	Amortization	33,535			33,535											
22																
23	Taxes															
24	Property	176,772			176,772											
25	Deferred Income Tax and ITC	(20,965)		27,682	6,716											
26	Federal and State Income Tax	12,689	1,101	(27,988)	(14,198)	969	619	(5)	(43)	38	9	(23)	464	(414)	6,108	95
27	Payroll and Other	27,477			27,477		(24)									(7)
28	Total Taxes	195,972	1,101	(306)	196,767	969	595	(5)	(43)	38	9	(23)	464	(414)	6,108	88
29																
30	Total Expenses	3,358,226	1,101	(306)	3,359,021	(2,403)	(1,535)	13	107	(95)	(23)	56	(1,150)	1,026	(15,144)	(236)
31																
32	Allowance for Funds Used During Construction	29,731			29,731											
33																
34	Total Operating Income	542,629	(1,101)	306	541,834	2,403	1,535	(13)	(107)	95	23	(56)	1,150	(1,026)	15,144	236
35																
36	Calculation of Revenue Requirements															
37	Rate Base	8,528,920	(169,536)	(111,999)	8,247,385											
38	Required Operating Income	604,700	(12,020)	(7,941)	584,740											
39	Operating Income	542,629	(1,101)	306	541,834	2,403	1,535	(13)	(107)	95	23	(56)	1,150	(1,026)	15,144	236
40	Income Deficiency	62,072	(10,919)	(8,247)	42,906	(2,403)	(1,535)	13	107	(95)	(23)	56	(1,150)	1,026	(15,144)	(236)
41	**Revenue Deficiency**	**87,109**	**(15,323)**	**(11,573)**	**60,212**	**(3,372)**	**(2,155)**	**19**	**150**	**(133)**	**(33)**	**79**	**(1,613)**	**1,440**	**(21,252)**	**(331)**
42																
43	Calculation of Income Taxes															
44	Operating Revenue	3,871,124			3,871,124											
45	-Operating Expense	2,553,485			2,553,485	(3,372)	(2,131)	19	150	(133)	(33)	79	(1,613)	1,440	(21,252)	(324)
46	-Amortization	33,535			33,535											
47	-Taxes Other then Income	183,283		27,682	210,965		(24)									(7)
48	Operating Income Before Adjs	1,100,820		(27,682)	1,073,138	3,372	2,155	(19)	(150)	133	33	(79)	1,613	(1,440)	21,252	331
49	Additions to Income	144,640		27,682	172,322											
50	Deductions from Income	777,555		254,377	1,031,933											
51	Debt Synchonization	192,754	(3,832)	(2,531)	186,391											
52	State Taxable Income	275,151	3,832	(251,846)	27,137	3,372	2,155	(19)	(150)	133	33	(79)	1,613	(1,440)	21,252	331
53	State Income Tax Before Credits	26,965	375	(24,681)	2,659	330	211	(2)	(15)	13	3	(8)	158	(141)	2,083	32
54	State Tax Credits	(1,205)		(2,437)	(3,642)											
55	Federal Tax Deductions															
56	Federal Taxable Income	249,391	3,456	(224,728)	28,120	3,042	1,943	(17)	(135)	120	30	(71)	1,455	(1,299)	19,170	298
57	Federal Income Tax Before Credits	52,372	726	(47,193)	5,905	639	408	(4)	(28)	25	6	(15)	306	(273)	4,026	63
58	Federal Tax Credits	(65,443)		46,323	(19,120)											
59	Total Income Taxes	12,689	1,101	(27,988)	(14,198)	969	619	(5)	(43)	38	9	(23)	464	(414)	6,108	95

Northern States Power Company

INCOME STATEMENT SCHEDULES
INCOME STATEMENT ADJUSTMENT SCHEDULES
2018 Unadjusted Actual Year versus 2018 Adjusted Actua
($000's)

1	2	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
			Adjustment													
Line No.	Description	Nuclear Retention	Pension: Non Qualified	Trading: Non Asset-Based Admin	XES Allocation on Labor Hours	Adjustments	CIP Incentive	Foundation Admin	LED Street Lighting	Monticello LCM/EPU Return	Nobles Amounts over CON	Nonplant and Other Rate Base	Service Quality	Trading: Non Asset-Based Margin	Amortization	NOL ADIT ARAM
1																
2	Operating Revenues															
3	Retail Revenue															
4	Interdepartmental															
5	Other Operating					(15,414)	19,297		284	13,370	202		553	(34,567)		
6	Total Revenue					(15,414)	19,297		284	13,370	202		553	(34,567)		
7																
8	Expenses															
9	Operating Expenses															
10	Fuel & Purchased Energy													(30,799)		
11	Power Production	(118)														
12	Transmission															
13	Distribution															
14	Customer Accounting															
15	Customer Service and Information						43,873									
16	Sales, Econ Dev, & Other															
17	Administrative and General		(1,140)	(1,542)	(4,250)			(148)								
18	Total Operating Expenses	(118)	(1,140)	(1,542)	(4,250)		43,873	(148)						(30,799)		
19																
20	Depreciation															
21	Amortization														19,283	2,269
22																
23	Taxes															
24	Property					11,048										
25	Deferred Income Tax and ITC											(1,142)				
26	Federal and State Income Tax	34	328	443	1,225	(7,606)	(7,064)	44	82	3,843	58	70	159	(1,083)	(5,542)	(332)
27	Payroll and Other				(13)			(4)								
28	Total Taxes	34	328	443	1,213	3,443	(7,064)	39	82	3,843	58	(1,071)	159	(1,083)	(5,542)	(332)
29																
30	Total Expenses	(84)	(812)	(1,098)	(3,038)	3,443	36,809	(109)	82	3,843	58	(1,071)	159	(31,882)	13,741	1,937
31																
32	Allowance for Funds Used During Construction															
33																
34	Total Operating Income	84	812	1,098	3,038	(18,856)	(17,512)	109	203	9,527	144	1,071	394	(2,685)	(13,741)	(1,937)
35																
36	Calculation of Revenue Requirements															
37	Rate Base											(10,850)				51,047
38	Required Operating Income											(769)				3,619
39	Operating Income	84	812	1,098	3,038	(18,856)	(17,512)	109	203	9,527	144	1,071	394	(2,685)	(13,741)	(1,937)
40	Income Deficiency	(84)	(812)	(1,098)	(3,038)	18,856	17,512	(109)	(203)	(9,527)	(144)	(1,841)	(394)	2,685	13,741	5,556
41	**Revenue Deficiency**	**(118)**	**(1,140)**	**(1,542)**	**(4,263)**	**26,462**	**24,576**	**(153)**	**(284)**	**(13,370)**	**(202)**	**(2,583)**	**(553)**	**3,768**	**19,283**	**7,798**
42																
43	Calculation of Income Taxes															
44	Operating Revenue					(15,414)	19,297		284	13,370	202		553	(34,567)		
45	-Operating Expense	(118)	(1,140)	(1,542)	(4,250)		43,873	(148)						(30,799)		
46	-Amortization														19,283	2,269
47	-Taxes Other then Income				(13)	11,048		(4)				(1,142)				
48	Operating Income Before Adjs	118	1,140	1,542	4,263	(26,462)	(24,576)	153	284	13,370	202	1,142	553	(3,768)	(19,283)	(2,269)
49	Additions to Income											(1,142)				2,269
50	Deductions from Income															
51	Debt Synchonization											(245)				1,154
52	State Taxable Income	118	1,140	1,542	4,263	(26,462)	(24,576)	153	284	13,370	202	245	553	(3,768)	(19,283)	(1,154)
53	State Income Tax Before Credits	12	112	151	418	(2,593)	(2,408)	15	28	1,310	20	24	54	(369)	(1,890)	(113)
54	State Tax Credits															
55	Federal Tax Deductions															
56	Federal Taxable Income	107	1,028	1,390	3,845	(23,869)	(22,167)	138	256	12,060	182	221	499	(3,399)	(17,393)	(1,041)
57	Federal Income Tax Before Credits	22	216	292	808	(5,012)	(4,655)	29	54	2,533	38	46	105	(714)	(3,653)	(219)
58	Federal Tax Credits															
59	Total Income Taxes	34	328	443	1,225	(7,606)	(7,064)	44	82	3,843	58	70	159	(1,083)	(5,542)	(332)
												(1,142)				

Northern States Power Company

Docket No. E002/GR-19-564
Financial Information
Schedule D - 2018

INCOME STATEMENT SCHEDULES
INCOME STATEMENT ADJUSTMENT SCHEDULES
2018 Unadjusted Actual Year versus 2018 Adjusted Actua
($000's)

1	2	32	33	34	35	36	37	38					
		Amortization				Rider Removals							Total
Line No.	Description	PI EPU Recovery	Rate Case Expenses	Sherco 3 Depr Deferral	Transco Costs	Renewable Connect	Rider: RES	Rider: TCR	Windsource	Cash Working Capital	Change in Cost of Capital	Net Operating Loss	
1													
2	Operating Revenues												
3	Retail Revenue						(3,615)	(1,116)					3,088,090
4	Interdepartmental												692
5	Other Operating	1,841				(5,912)		(93,889)	(6,687)				656,690
6	Total Revenue	1,841				(5,912)	(3,615)	(95,005)	(6,687)				3,745,473
7													
8	Expenses												
9	Operating Expenses												
10	Fuel & Purchased Energy					(5,562)			(5,891)				1,079,928
11	Power Production												608,940
12	Transmission							(93,714)					221,568
13	Distribution												108,027
14	Customer Accounting												49,110
15	Customer Service and Information												146,674
16	Sales, Econ Dev, & Other												46
17	Administrative and General												212,730
18	Total Operating Expenses					(5,562)		(93,714)	(5,891)				2,427,024
19													
20	Depreciation												575,233
21	Amortization	2,884	9,015	503	(312)								67,177
22													
23	Taxes												
24	Property												187,821
25	Deferred Income Tax and ITC	(1,179)		(272)			92					(3,634)	581
26	Federal and State Income Tax	354	(2,591)	(32)	90	(101)	(891)	(285)	(229)	15	2,852	3,622	(18,915)
27	Payroll and Other												27,428
28	Total Taxes	(825)	(2,591)	(304)	90	(101)	(799)	(285)	(229)	15	2,852	(12)	196,915
29													
30	Total Expenses	2,059	6,424	199	(223)	(5,663)	(799)	(93,998)	(6,119)	15	2,852	(12)	3,266,350
31													
32	Allowance for Funds Used During Construction												29,731
33													
34	Total Operating Income	(218)	(6,424)	(199)	223	(249)	(2,816)	(1,007)	(567)	(15)	(2,852)	12	508,854
35													
36	Calculation of Revenue Requirements												
37	Rate Base	26,997		4,881			(37,221)	(13,309)		(2,375)		1,817	8,268,371
38	Required Operating Income	1,914		346			(2,639)	(944)		(168)	36,381	129	622,608
39	Operating Income	(218)	(6,424)	(199)	223	(249)	(2,816)	(1,007)	(567)	(15)	(2,852)	12	508,854
40	Income Deficiency	2,132	6,424	545	(223)	249	177	63	567	(153)	39,233	117	113,754
41	**Revenue Deficiency**	**2,992**	**9,015**	**765**	**(312)**	**350**	**248**	**89**	**796**	**(215)**	**55,057**	**164**	**159,637**
42													
43	Calculation of Income Taxes												
44	Operating Revenue	1,841				(5,912)	(3,615)	(95,005)	(6,687)				3,745,473
45	-Operating Expense					(5,562)		(93,714)	(5,891)				2,427,024
46	-Amortization	2,884	9,015	503	(312)								67,177
47	-Taxes Other then Income	(1,179)		(272)			92					(3,634)	215,830
48	Operating Income Before Adjs	136	(9,015)	(231)	312	(350)	(3,706)	(1,292)	(796)			3,634	1,035,442
49	Additions to Income	1,705		231			(234)					(3,634)	171,517
50	Deductions from Income												1,031,933
51	Debt Synchonization	610		110			(841)	(301)		(54)	(9,922)	41	176,943
52	State Taxable Income	1,231	(9,015)	(110)	312	(350)	(3,100)	(991)	(796)	54	9,922	(41)	(1,917)
53	State Income Tax Before Credits	121	(883)	(11)	31	(34)	(304)	(97)	(78)	5	972	(4)	(188)
54	State Tax Credits												(3,642)
55	Federal Tax Deductions												
56	Federal Taxable Income	1,110	(8,132)	(99)	282	(316)	(2,796)	(894)	(718)	48	8,950	(37)	1,913
57	Federal Income Tax Before Credits	233	(1,708)	(21)	59	(66)	(587)	(188)	(151)	10	1,879	(8)	402
58	Federal Tax Credits											3,634	(15,486)
59	Total Income Taxes	354	(2,591)	(32)	90	(101)	(891)	(285)	(229)	15	2,852	3,622	(18,915)
		(1,179)		(272)			92					(3,634)	(6,135)

Adjustment Type	Adjustment	Adjustment Description
Adjustment	Advertising	Traditional adjustment made for advertising costs to adjust to allowed level of recovery
Adjustment	Aviation	Traditional adjustment removing 100% of aviation costs
Adjustment	Customer Deposits Expense	Traditional adjustment made for interest on customer deposits to adjust to allowed level of recovery
Adjustment	Dues: Chamber of Commerce	Traditional adjustment made for Chamber of Commerce dues to adjust to allowed level of recovery
Adjustment	Dues: Professional Associations	Traditional adjustment made for Association Dues to adjust to allowed level of recovery
Adjustment	Economic Development Admin	Traditional adjustment made for economic development costs to adjust to allowed level of recovery
Adjustment	Economic Development Donations	Traditional adjustment made for economic development donations to adjust to allowed level of recovery
Adjustment	Employee Expenses	Excludes items not eligible for recovery
Adjustment	Foundation and Other Donations	Traditional adjustment made for donations to adjust to allowed level of recovery
Adjustment	Incentive Compensation	Removal of AIP over 15% of base salary and long term incentive
Adjustment	Investor Relations	Removes 50% of Investor Relations O&M costs
Adjustment	Nuclear Retention	Excludes from recovery nuclear retention related costs
Adjustment	Pension: Non Qualified	Excludes from recovery non-qualified pension
Adjustment	Trading: Non Asset-Based Admin	Remove costs of generating the shareholder portion of non-asset based trading margins.
Adjustment	XES Allocation on Labor Hours	Adjustment for alternate common cost allocation method
Adjustment	Adjustments	Excludes items not eligible for recovery
Adjustment	CIP Incentive	Removes the CIP performace incentive revenues
Adjustment	Foundation Admin	Removes 100% of Foundation Administration O&M costs
Adjustment	LED Street Lighting	Reflects the LED Street Lighting deferral requested in 2020-2022 MYRP
Adjustment	Monticello LCM/EPU Return	Adjustment for Monticello LCM/EPU based on Commission order
Adjustment	Nobles Amounts over CON	Removes the portion of the Nobles Wind Farm disallowed from rate base recovery in Docket No. E002/GR-12-961
Adjustment	Nonplant and Other Rate Base	Non-Plant Excess ADIT
Adjustment	Service Quality	Remove all service quality revenue
Adjustment	Trading: Non Asset-Based Margin	Removes revenue and expenses related to Non Asset-Based trading
Rate Case Adjustments - amortizations	Amortization	Amortization
Rate Case Adjustments - amortizations	NOL ADIT ARAM	Reflects the amorization level per Commission's Order in Docket No. E,G-999/CI-17-895 in the 2020-2022 MYRP
Rate Case Adjustments - amortizations	PI EPU Recovery	Reflects the PI EPU costs deferred in Docket No. E002/GR-13-868 in the 2020-2022 MYRP
Rate Case Adjustments - amortizations	Rate Case Expenses	Amortization of rate case related expenses
Rate Case Adjustments - amortizations	Sherco 3 Depr Deferral	Reflects the Sherco 3 costs deferred in Docket No. E002/GR-13-868 in the 2020-2022 MYRP
Rate Case Adjustments - amortizations	Transco Costs	Transco Costs
Rider Removal	Renewable Connect	Removal of expenses related to Renewable*Connect rider; inclusion of capacity credit
Rider Removal	Rider: RES	Removes revenue and expense that will continue to be collected through the RES rider
Rider Removal	Rider: TCR	Removes revenue and expense that will continue to be collected through the TCR rider
Rider Removal	Windsource	Removal of expenses related to Windsource rider; inclusion of capacity credit

Descriptions of Assumptions and Approaches Used In Developing the Projected Year

This Schedule provides a list of assumptions used to develop the projected year, and meets the requirements of Minn. Rules pt. 7825.4000 (D) and (E), related to the rate base, and pt. 7825.4100 (E) and (F), related to the operating income.

ELECTRIC MWH SALES

The Sales, Energy and Demand Forecasting area in the Revenue Requirements Department coordinates the preparation of the electric MWh sales, peak demand and customer forecasts. The sales and customer forecasts are jointly developed and are extensively reviewed by management before they are included in the forecast updates.

Xcel Energy uses a combination of forecasting techniques to develop the sales forecast. The forecast is developed for the following customer classes:

Residential with Electric Space Heating
Residential without Electric Space Heating
Small Commercial & Industrial
Large Commercial & Industrial
Other Sales to Public Authorities
Public Street & Highway Lighting
Interdepartmental Sales

Regression models provided the foundation for the sales forecasts of the Residential without Space Heating, Residential with Space Heating, Small Commercial and Industrial, Large Commercial and Industrial, Other Sales to Public Authorities, and Public Street & Highway Lighting customer classes. Regression techniques are very well known and proven methods of forecasting and are commonly accepted by forecasters throughout the utility industry. This method provides reliable, accurate projections, accommodates the use of predictor variables, such as economic or demographic indicators and weather, and allows clear interpretation of the model. Xcel Energy has been using these types of regression models since 1991.

Monthly sales forecasts for these customer classes were developed based on regression models designed to define a statistical relationship between the historical sales and the independent predictor variables, including historical economic and demographic indicators, historical weather (expressed in heating degree days and temperature-humidity index ("THI")), and historical number of customers. In all of the models, monthly historical data from January 2003 through May 2019 was used to determine these relationships. The modeled relationships were then simulated over the forecast period by assuming normal weather (expressed in terms of twenty-year averaged heating degree days and temperature-humidity index ("THI")) and the projected levels of the independent predictor variables.

Sales in the Interdepartmental customer class make up less than one-tenth of one percent of total retail sales in Minnesota in the test year. Usage in this customer class often is impacted by factors that are difficult to capture in a regression model. Therefore, the forecast for this customer class was developed by averaging historical monthly sales over the past three years of actual data.

External Data Sources

IHS Markit provided economic and demographic data series, both historical and forecast. Historical weather data was obtained from the National Oceanic and Atmospheric Administration ("NOAA") as measured at its Minneapolis-St. Paul weather station. Forecast weather is presumed to be normal, expressed in terms of twenty-year averaged heating degree days and THI.

Calendar Month Sales Adjustment

The methodology explained above produces the Company's sales forecast on a billing month basis. For purposes of projected year revenue development, an adjustment by class for unbilled sales is also made to reflect sales on a calendar month basis.

For additional information on the development of the test year sales forecast, please see the direct testimony of Ms. Jannell E. Marks, Director of Sales, Energy, and Demand Forecasting for Xcel Energy Services, Inc.

REVENUE DEVELOPMENT

Filing requirements mandate that sales and revenues be provided by service schedule. This information is developed by the Electric Pricing Area, and is included as a schedule in section 6 of this Volume.

The process begins with projected year calendar month electric sales and customer counts, which are provided by the Sales, Energy and Demand Forecasting area, and developed by the method described previously in the Schedule. Electric sales and customer counts are forecast for the major customer classes of Residential With

Space Heating, Residential Without Space Heating, Small Commercial & Industrial, Large Commercial & Industrial, Street and Highway Lighting, Other Sales to Public Authorities, and Inter-departmental Sales.

The projected year sales and customer data by major customer class are then refined into sub-class detail and billing demands according to historical trends and relationships in order to estimate projected year calendar month billing data. The resulting projected year billing data is then applied to present and proposed rate levels to determine revenues by rate schedule.

OPERATING EXPENSES

Production Expenses

The annual forecast of electric production expense is prepared using a computer simulation of the electric energy production activity for the year in question. This simulation estimates the fuel consumption of each generating unit required to supply the energy requirements that are forecast, taking into account anticipated purchases and sales of energy with other utilities.

Business Area Operating Expense

The budget process is described in detail in volume VI. The budgets used in the development of the 2020 test year cost of service are based on a combination of projected expenses and known changes to expense levels developed as part of the 2020 annual budget process. The projected changes are determined using the below described factors. Wherever there was a known change in the business, a projected amount was included in the budget to reflect that known change. The budgets for both O&M and Capital Expenditures are developed within each business area of Xcel Energy.

Business area operating expense budgets are prepared by each of the responsible managers of Xcel Energy. Operating expense budgets are prepared for each applicable Xcel Energy legal entity. Business areas prepare a separate budget for NSP-Minnesota, each of the other Xcel Energy utility companies and Xcel Energy Services Inc. (the Service Company).

Expenses are categorized as either Operating Labor or Operating Non-Labor. Managers are responsible for creating the annual budget for their organization. Each manager uses the best information available including historical cost trends, vendor cost quotes, project estimates, etc., as well as information provided from Corporate which includes contracted wage increases for union employees, estimated wage increases for non-union employees, transportation rates, purchasing and warehousing rates, overall inflation/escalation factors, etc. As part of the process, each area assigns the expenses to the proper business unit, cost element and internal order (where appropriate). The combination of those items determines the assignment to the appropriate legal entity, utility (electric or gas) and FERC account to which the expenses are recorded.

As noted above, business areas are responsible for assigning the appropriate costs to NSP-Minnesota and appropriately to the electric and gas utilities. The business areas are not responsible for forecasting jurisdictional expenses. Once the forecasts are developed in total for NSP-Minnesota and by utility, the rate area assigns those costs to the proper jurisdictions. The assumptions and approaches used to develop the jurisdictional assignments are described in the testimony of Melissa Schmidt and Benjamin Halama.

As noted above, there are two primary components of the O&M forecast:

1) Labor Expenses
2) Non-Labor Expenses

-Labor

Operating Labor includes productive labor dollars plus a corporate average labor additive component to cover non-productive time. Employee-related expenses such as pension costs, medical and group life insurance, and worker's compensation are the responsibility of the Shared Services business area and are included in Administrative and General Expenses.

Preparation of the operating labor forecast begins with a determination of employee needs for the coming year. The labor costs are developed by entering individual employee wage information, applying the contractual wage increase for union employees and an estimated wage increase for all other employees, determined by the Shared Services business area and determining productive hours/dollars, then adding a corporate average labor additive component to cover expenses associated with non-productive time (vacation, sick leave, other/injury, inclement weather, holidays).

Each business area is responsible for entering the forecast of labor dollars into the on-line budget system and assigning the labor to the appropriate business unit, labor cost element and internal order (where appropriate). The combination of these items determines the costs applicable to legal entity, utility, and FERC account (including capital labor assignment).

Pension, medical and workers compensation costs are projected costs forecast by the Shared Services business area with the assistance of an independent actuarial service. Payroll taxes for the most recent twelve month actuals are used in the budget year and the projected labor costs. These costs are applied to labor through a loading factor, which accomplishes assigning the appropriate amount of labor related benefits to operating labor and capital labor.

The Shared Services business area is also responsible for forecasting the incentive compensation costs to be included in the budget. Incentive compensation costs associated with NSP-Minnesota employees are included in the operating labor budget as a part of Administrative and General costs. Labor costs assigned to NSP-Minnesota from the Service Company include incentive compensation as a portion of the labor overhead allocation and therefore, are included as costs in the same FERC account as the assigned labor costs.

-Non Labor

Non-labor expenses include the costs associated with helping employees complete their tasks, such as materials, transportation, supplies and other expenses. As noted above, business area managers are responsible for projecting non labor costs using the best information available. Any known business changes for the budget year are incorporated using the best cost projections available at the time the budget is created.

As with labor costs, each business area is responsible for assigning the non labor costs to the appropriate, business unit, cost element and internal order (where appropriate). The combination of these items determines the costs applicable to legal entity, utility, and FERC account (including capital labor assignment). The FERC number is used as the basis to develop electric or gas costs of service studies.

Other Expenses

-Depreciation and Amortization

Book depreciation expense is a projected expense based on projected average monthly plant in service by functional class multiplied times one-twelfth of the annual straight-line depreciation rate developed for each functional guideline class. The depreciation lives and rates used are those proposed by the Company in Docket E,G002/D-19-161 for electric production and E,G002/D-18-523 for electric transmission, distribution, general and common general and intangible. The depreciation reserve is initialized from Company records from the most recent end-of-year. This reserve, plus the estimate of monthly net changes such as provision and retirements, provides each new end of year balance. Book Depreciation and other plant-related items are provided by the Capital Asset Accounting business area.

-Income Taxes (Current/Deferred)

The Capital Asset Accounting business area is responsible for the calculation of plant-related items such as tax depreciation, investment tax credit flow through and deferred income taxes, all of which are projected expenses. Deferred income taxes and accumulated deferred tax balances are developed for each functional guideline class for each vintage of property addition based on the difference between tax depreciation and straight line depreciation using the most recent certified and Commission approved book depreciation lives. Income tax depreciation is also calculated on a property vintage basis using the appropriate depreciation methods as defined in the Internal Revenue Code Sections 167 and 168 and supporting Regulations. Historical actual balances for the tax depreciation reserve and accumulated deferred taxes are incorporated into the forecast process along with forecast plant addition and retirement information to produce the forecast expenses, deductions and balances. The Corporate Income Tax business area provides additional tax expense and deferred tax information for various non-plant related items.

-Property Taxes

NSP-Minnesota's electric utility plant in service including the allocated portion of common plant is assessed property taxes based on the value of its property and is a projected expense. The level of expense for the budget year is projected by the corporate Property Tax area based on historical property tax assessments updated with projected changes to the market value of the taxed property and projected changes to the state and local tax rates. The corporate Property Tax area monitors activity in the state legislature and local taxing authorities on an ongoing basis and uses the most recent information available when the budget is created.

Cost Allocations and Assignments.

Melissa Schmidt's testimony explains in detail the assumptions and approaches used to assign and allocate costs to the business areas in developing the projected year. The testimony also provides the Service Agreement used to assign and allocate Service Company costs and the NSP-Minnesota Cost Assignment and Allocation Manual (CAAM) which explain the assumptions and approaches used to assign and allocate costs. Costs are assigned or allocated between regulated and unregulated businesses, between the gas and electric utilities, and between jurisdictions. Benjamin C. Halama provides the Minnesota jurisdictional cost study.

Business areas with Service Company employees and expenses are responsible for assigning the Service Company costs to the appropriate Xcel Energy operating company or affiliate based on the services provided, and in accordance with the SEC and Minnesota Commission approved Service Agreement. Costs from the Service Company are direct assigned to legal entities where possible. Costs that are not directly attributable to a specific legal entity are allocated to the appropriate legal entity through use of approved allocation factors based on the type of service being performed.

CAPITAL EXPENDITURES

The capital budgeting process is explained in detail in volume VI. Each business area is responsible for forecasting capital expenditures by project. The capital expenditures for individual projects are for known projects and reflect actual projected costs. The expenditures for general maintenance, new business and government ordered relocates are based on historical trends, economic forecasts, estimated new meters (which is based on customer growth expectations discussed above, as well as any nondiscretionary work (known relocates)). The capital expenditure budgets are entered by the business areas into the on line budget system with the appropriate information to enable calculation of the plant related information discussed above. The capital expenditure information is interfaced to the plant system for the calculations to be performed.

JURISDICTIONAL ASSIGNMENT

The revenue requirement area is responsible for the assignment of the O&M and Capital expenditure amounts to the jurisdictions that NSP- Minnesota serves. The assumptions and approaches used to make the jurisdictional assignment is detailed in the NSP-Minnesota CAAM and described in the testimonies of Ms. Melissa Schmidt and Mr. Benjamin Halama.

Line No.	Description	Allocation Basis
	The allocation factors on this page were used to determine Minnesota jurisdictional operating income amounts for all of the years presented in these schedules. Accounts not on this page have been directly asigned to jurisdiction.	
1	Fuel & Purchased Energy	Energy
2	Power Production Expense	Demand - Production Energy
3	Transmission Expense	Demand - Transmission
4	Distribution Expense	Customers
5	Customer Accounting Expense	Customers
6	Customer Service & Info Expense	Customers
7	Sales Expense	Customers
8	Administrative & General	Customers Demand - Production Demand - Transmission TwoFactor

	Most Recent Fiscal Year 2018				Projected Fiscal Year 2019				Proposed Test Year 2020, Plan Years 2021 & 2022			
Line No.	Allocation Factor	Total Utility	Minnesota Jurisdiction	Allocation Factor	Allocation Factor	Total Utility	Minnesota Jurisdiction	Allocation Factor	Allocation Factor	Total Utility	Minnesota Jurisdiction	Allocation Factor
1	Demand - Prod(1)	67,498,442	59,188,021	87.6880%	Demand - Prod(1)	64,459,483	56,079,105	86.9990%	Demand - Prod(1)	64,459,483	56,079,105	86.9990%
2	Demand - Tran (2)	67,498,442	59,188,021	87.6880%	Demand - Tran (2)	64,459,483	56,079,105	86.9990%	Demand - Tran (2)	64,459,483	56,079,105	86.9990%
3	Energy (3)	35,974,452	31,358,488	87.1688%	Energy (3)	34,275,058	29,715,088	86.6960%	Energy (3)	34,275,058	29,715,088	86.6960%
4	Customers(4)	1,478,542	1,290,003	87.2483%	Customers(4)	1,503,224	1,311,282	87.2313%	Customers(4)	1,503,224	1,311,282	87.2313%
5	TwoFactor	100.0000%	87.5736%	87.5736%	TwoFactor(5)	100.0000%	87.0622%	87.0622%	TwoFactor(5)	100.0000%	87.0622%	87.0622%

(1) Demand w/o Contract Services
(2) Demand
(3) Energy
(4) Average number of Customers
(5) TwoFactor

		Unadjusted Test Year 2020, Plan Years 2021 & 2022		
Line No.	Allocation Factor	Total Utility	Minnesota Jurisdiction	Allocation Factor
1	Demand - Production	64,459,483	56,079,105	86.9990%
2	Demand - Transmission	64,459,483	56,079,105	86.9990%
3	Energy	34,275,058	29,715,088	86.6960%
4	Customers	1,503,224	1,311,282	87.2313%
5	TwoFactor	see page 4		

(1) Demand w/o Contract Services
(2) Demand
(3) Energy
(4) Average number of Customers
(5) TwoFactor

Alloctors for Common and General Plant
for 2020 Unadjusted and Proposed Test Years, Plan Years 2021 & 2022
Based on 2018 Actual Data

O&M Allocator

O&M excluding A&G	2018 Actuals	Ratio
Production	559,099,285	64.34%
Transmission	49,285,608	5.67%
Distribution/Customer	260,636,741	29.99%
	$ 869,021,633	100.00%

Plant in Service used to allocate Electric General Plant
Source - 2018 FERC Form 1
Pages 204-207

	2018 Year End Balance	Ratio
Production	$ 9,122,369,561	53.78%
Transmission	$ 3,702,252,913	21.83%
Distribution	$ 4,136,835,009	24.39%
	$16,961,457,483	100.00%

Combined Allocator used for Electric Portion of Common Plant
Equally Weighted Plant in Service and O&M ratio

Production	59.0600%
Transmission	13.7500%
Distribution	27.1900%
	100.0000%

20 Budget Allocators

EProd Demand Alloc

MN	86.9990%
ND	6.1920%
SD	6.8090%
WHLSL	0.0000%
	100.0000%

ETrans Demand Alloc

MN	86.9990%
ND	6.1920%
SD	6.8090%
WHLSL	0.0000%
	100.0000%

ECustomerMN/SD/ND

MN	87.2313%
ND	6.3228%
SD	6.4459%
WHLSL	0.0000%
	100.0000%

2016 Budget A&G Jurisdicational Allocators

ELECTRIC A&G Alloc

2 Factor Allocator	O&M and Plant	MN	ND	SD	WHLSL	Check
Production	59.0600%	51.3816%	3.6570%	4.0214%	0.0000%	59.0600%
Transmission	13.7500%	11.9624%	0.8514%	0.9362%	0.0000%	13.7500%
Distribution/Customers	27.1900%	23.7182%	1.7192%	1.7526%	0.0000%	27.1900%
Resulting Allocator	**100.00%**	**87.0622%**	**6.2276%**	**6.7102%**	**0.0000%**	**100.0000%**

RATE OF RETURN COST OF CAPITAL SCHEDULES
(PART 7825.4200)

The following rate of return cost of capital schedules as required by parts 7825.3800 and 7825.4200 shall be filed:

A. A rate of return cost of capital summary schedule showing the calculation of the weighted cost of capital using the average capital structures for the most recent fiscal year the projected fiscal year and projected test year. This information shall be provided for the unconsolidated parent and subsidiary corporations, and for the consolidated parent corporation.

B. Supporting schedules showing the 12 month average balance calculation of the embedded cost of long-term debt, the end of the most recent fiscal year, the projected fiscal year and projected test year

C. Schedule showing the 12 month average short-term securities for the most recent fiscal year, the proposed fiscal year and proposed test year.

D. Schedule showing 13 month average balance of Common Equity Balances for the most recent fiscal year, proposed fiscal year and proposed test year.

E. There are no Preferred Equity Balances.

Tab A-1, A3 and A4 includes schedules per 7825.4200 (A)

Tab LTD includes schedules per 7825.4200 (B)

Tab STD includes schedules per 7825.4200 (C)

Tab CE includes Average Common Equity Balances (D)

Tab PE includes Average Preferred Equity Balances (E)

NSPM Electric Rate Case - 2020 Test Year Capital Structure Compliance Schedules

Rate Case Docket Number E002/GR-19-564

Purpose :
Submitted as part of "Volume 3" additional supporting schedules.
Includes NSPM 2018 Actuals, 2019 Bridge Year and 2020 Test Year. Also includes Xcel Consolidated for 2018, 2019 and 2020.

11 Workbooks			Page (s)
	NSPM Utility Schedules - Equity Adjusted for UP&L		
1	A-1	2018 Actual, 2019 Forecasted and 2020 Proposed Capital Structure	1
2	A-1-LTD-1	2018 Actual Long Term Debt Cost	2
	A-1-LTD-2	2019 Current Year Long Term Debt Cost	3
	A-1-LTD-3	2020 Proposed Long Term Debt Cost	4
3	A-1-STD	2018 Actual, 2019 Forecasted and 2020 Proposed Cost of Short Term Debt	5
4	A-1-STD	2018 Actual, and 2019 Forecasted and 2020 Proposed Short Term Debt Balances	6
5	A-1-CE	2018 Actual, 2019 Forecasted and 2020 Proposed Subsidiary Adjusted Equity Balances	7

	NSPM Consolidated Schedules		
6	A-3	2018 Unadjusted Actual, 2019 Forecasted & 2020 Proposed Capital Structure.	8
7	A-3-LTD-1	2018 Actual Long Term Debt Cost	9
	A-3-LTD-2	2019 Current Year Long Term Debt Cost	10
	A-3-LTD-3	2020 Proposed Long Term Debt Cost	11
8	A-3-STD	2018 Actual, 2019 Forecasted and 2020 Proposed Cost of Short Term Debt	12
9	A-3-STD	2018 Actual, 2019 Forecased and 2020 Proposed Short Term Debt Balances	13
10	A-3-CE	2018 Actual, 2019 Forecasted and 2020 Propsed Equity Balances - No Subsidiary Adjustment	14

	Xcel Energy Consolidated Schedules		
11	A-4	2018, 2019 and 2020 Xcel Energy Consolidated Capital Structure Summary	15
	A-4-STD	2018, 2019 and 2020 Xcel Energy Consolidated Short Term Debt Balances and Costs	16
	A-4-LTD-1…P.1 of 2	2018 Xcel Energy Consolidated LongTerm Debt Balances	17
	A-4-LTD-1…P.2 of 2	2018 Xcel Energy Consolidated LongTerm Debt Balances and Costs	18
	A-4-LTD-2…P.1 of 2	2019 Xcel Energy Consolidated LongTerm Debt Balances	19
	A-4-LTD-2…P.2 of 2	2019 Xcel Energy Consolidated LongTerm Debt Balances and Costs	20
	A-4-LTD-3…P.1 of 2	2020 Xcel Energy Consolidated LongTerm Debt Balances	21
	A-4-LTD-3…P.2 of 2	2020 Xcel Energy Consolidated LongTerm Debt Balances and Costs	22
	A-4-PE	2018, 2019 and 2020 Xcel Energy Consolidated Preferred Stock Balances and Costs	23
	A-4-CE	2018, 2019 and 2020 Xcel Energy Consolidated Common Stock Balances	24

PROPOSED TEST YEAR 2020 COST OF CAPITAL

Capitalization:	**($000's) Amount**	**Percent of Total Capitalization**	**Cost of Capital**	**Weighted Cost of Capital***
Long-Term Debt	$5,857,314	46.63%	4.35%	2.03%
Short-Term Debt	$108,986	0.87%	2.97%	0.03%
			26.00%	
Total Debt	$5,966,300	47.50%		2.06%
Net Common Equity	$6,594,458	52.50%	10.20%	5.36%
Total Capitalization	$12,560,758	100.00%		7.42%

Short Term Debt and Long Term Debt Amounts are 12 Month Average Balances.
Equity Amounts are 13 Month Average Balances.

PROPOSED ADDITIONAL PLAN YEAR 2021 COST OF CAPITAL

Capitalization:	**($000's) Amount**	**Percent of Total Capitalization**	**Cost of Capital**	**Weighted Cost of Capital***
Long-Term Debt	$6,267,923	46.28%	4.37%	2.02%
Short-Term Debt	$165,327	1.22%	2.99%	0.04%
Total Debt	$6,433,250	47.50%		2.06%
Net Common Equity	$7,109,797	52.50%	10.20%	5.36%
Total Capitalization	$13,543,047	100.00%		7.42%

Short Term Debt and Long Term Debt Amounts are 12 Month Average Balances.
Equity Amounts are 13 Month Average Balances.

PROPOSED ADDITIONAL PLAN YEAR 2022 COST OF CAPITAL

Capitalization:	**($000's) Amount**	**Percent of Total Capitalization**	**Cost of Capital**	**Weighted Cost of Capital***
Long-Term Debt	$6,552,021	46.42%	4.41%	2.05%
Short-Term Debt	$151,836	1.08%	3.04%	0.03%
Total Debt	$6,703,857	47.50%		2.08%
Net Common Equity	$7,409,590	52.50%	10.20%	5.36%
Total Capitalization	$14,113,447	100.00%		7.44%

Short Term Debt and Long Term Debt Amounts are 12 Month Average Balances.
Equity Amounts are 13 Month Average Balances.

Northern States Power Company (Minnesota) | Docket No. E002/GR-19-564
Regulated Electric Utility - State of Minnesota | Financial Information
RATE OF RETURN COST OF CAPITAL SCHEDULES | Schedule A-1
SUMMARY SCHEDULES | Page 1 of 1
($000's)

Capitalization:	Amount (A)	Percent of Total Capitalization (B)	Cost of Capital (C)	Weighted Cost of Capital (D)
ADJUSTED MOST RECENT FISCAL YEAR 2018				
Long-Term Debt	$4,888,050	46.49%	4.56%	2.12%
Direct Borrowings Under Multi-Year Credit Facility	$0	0.00%	0.00%	0.00%
Short-Term Debt	$71,550	0.68%	2.97%	0.02%
Total Short-Term Debt	$71,550	0.68%		0.02%
Long-Term and Short-Term Debt	$4,959,600	47.17%		2.14%
Preferred Stock	$0	0.00%	0.00%	0.00%
Net Common Equity	$5,554,691	52.83%	10.20%	5.39%
Total Equity	$5,554,691	52.83%		5.39%
Total Capitalization	$10,514,291	100.00%		7.53%
ADJUSTED PROJECTED FISCAL YEAR 2019				
Long-Term Debt	$5,092,482	45.46%	4.45%	2.02%
Direct Borrowings Under Multi-Year Credit Facility	$0	0.00%	0.00%	0.00%
Short-Term Debt	$184,545	1.65%	2.71%	0.04%
Total Short-Term Debt	$184,545	1.65%		0.04%
Long-Term and Short-Term Debt	$5,277,027	47.11%		2.06%
Preferred Stock	$0	0.00%	0.00%	0.00%
Net Common Equity	$5,925,360	52.89%	10.20%	5.39%
Total Equity	$5,925,360	52.89%		5.39%
Total Capitalization	$11,202,387	100.00%		7.45%
ADJUSTED "PROPOSED" TEST YEAR 2020				
Long-Term Debt	$5,857,314	46.63%	4.35%	2.03%
Direct Borrowings Under Multi-Year Credit Facility	$0	0.00%	0.00%	0.00%
Short-Term Debt	$108,986	0.87%	2.97%	0.03%
Total Short-Term Debt	$108,986	0.87%		0.03%
Long-Term and Short-Term Debt	$5,966,300	47.50%		2.06%
Preferred Stock	$0	0.00%	0.00%	0.00%
Net Common Equity	$6,594,458	52.50%	10.20%	5.36%
Total Equity	$6,594,458	52.50%		5.36%
Total Capitalization	$12,560,758	100.00%		7.42%

All are average balances; long term and short term debt based on 12 month averages, common equity based on 13 month averages.

Northern States Power Company (Minnesota)
Consolidated - Unadjusted
RATE OF RETURN COST OF CAPITAL SCHEDULES
SUMMARY SCHEDULES
($000's)

Docket No. E002/GR-15-826
Financial Information
Schedule A-3
Page 1 of 1

Capitalization:	Amount (A)	Percent of Total Capitalization (B)	Cost of Capital (C)	Weighted Cost of Capital (D)
UNADJUSTED MOST RECENT FISCAL YEAR 2018				
Long-Term Debt	$4,888,050	46.49%	4.56%	2.12%
Direct Borrowings Under Multi-Year Credit F	$0	0.00%	0.00%	0.00%
Short-Term Debt	$71,550	0.68%	2.97%	0.02%
Total Short-Term Debt	$71,550	0.68%		0.02%
Long-Term and Short-Term Debt	$4,959,600	47.17%		2.14%
Preferred Stock	$0	0.00%	0.00%	0.00%
Net Common Equity	$5,555,608	52.83%	10.20%	5.39%
Total Equity	$5,555,608	52.83%		5.39%
Total Capitalization	$10,515,208	100.00%		7.53%
UNADJUSTED PROJECTED FISCAL YEAR 2019				
Long-Term Debt	$5,092,482	45.46%	4.45%	2.03%
Direct Borrowings Under Multi-Year Credit F	$0	0.00%	0.00%	0.00%
Short-Term Debt	$184,545	1.65%	2.71%	0.04%
Total Short-Term Debt	$184,545	1.65%		0.04%
Long-Term and Short-Term Debt	$5,277,027	47.10%		2.07%
Preferred Stock	$0	0.00%	0.00%	0.00%
Net Common Equity	$5,926,307	52.90%	10.20%	5.40%
Total Equity	$5,926,307	52.90%		5.40%
Total Capitalization	$11,203,334	100.00%		7.47%
UNADJUSTED PROPOSED TEST YEAR YEAR 2020				
Long-Term Debt	$5,857,314	46.63%	4.35%	2.02%
Direct Borrowings Under Multi-Year Credit F	$0	0.00%	0.00%	0.00%
Short-Term Debt	$108,986	0.87%	2.97%	0.03%
Total Short-Term Debt	$108,986	0.87%		0.03%
Long-Term and Short-Term Debt	$5,966,300	47.50%		2.05%
Preferred Stock	$0	0.00%	0.00%	0.00%
Net Common Equity	$6,595,388	52.50%	10.20%	5.36%
Total Equity	$6,595,388	52.50%		5.36%
Total Capitalization	$12,561,688	100.00%		7.41%

All are average balances; long term and short term debt based on 12 month averages, common and preferred equity based on 13 month balances.

Xcel Energy Inc.
Consolidated
RATE OF RETURN COST OF CAPITAL SCHEDULES
SUMMARY SCHEDULES
($000's)

Docket No. E002/GR-19-564
Financial Information
Schedule A-4

Capitalization:	Amount (A)	Percent of Total Capitalization (B)	Cost of Capital (C)	Weighted Cost of Capital (D)
MOST RECENT FISCAL YEAR 2018				
Long-Term Debt	$15,455,302	54.99%	4.36%	2.40%
Short-Term Debt	$840,667	2.99%	2.63%	0.08%
Long-Term and Short-Term Debt	$16,295,968	57.98%		2.48%
Preferred Stock	$0	0.00%	0.00%	0.00%
Net Common Equity	$11,808,148	42.02%	10.20%	4.29%
Total Equity	$11,808,148	42.02%		4.29%
Total Capitalization	$28,104,116	100.00%		6.77%
PROJECTED FISCAL YEAR 2019				
Long-Term Debt	$17,098,823	54.95%	4.31%	2.37%
Short-Term Debt	$1,339,395	4.30%	3.03%	0.13%
Long-Term and Short-Term Debt	$18,438,218	59.25%		2.50%
Preferred Stock	$0	0.00%	0.00%	0.00%
Net Common Equity	$12,674,918	40.74%	10.20%	4.16%
Total Equity	$12,674,918	40.74%		4.16%
Total Capitalization	$31,113,136	99.99%		6.66%
PROJECTED FISCAL YEAR 2020				
Long-Term Debt	$19,187,411	56.58%	4.27%	2.42%
Short-Term Debt	$1,173,751	3.46%	3.19%	0.11%
Long-Term and Short-Term Debt	$20,361,162	60.04%		2.53%
Preferred Stock (Redeemed 10/31/11)	$0	0.00%	0.00%	0.00%
Net Common Equity	$13,545,838	39.96%	10.20%	4.08%
Total Equity	$13,545,838	39.96%		4.08%
Total Capitalization	$33,907,000	100.00%		6.61%

All are average balances; long term debt is based on average end of year balances;
short term debt balances are twelve month averages, common and preferred equity are thirteen month averages.

Northern States Power Company (Minnesota)
Regulated Electric Utility - State of Minnesota
RATE OF RETURN COST OF CAPITAL SCHEDULES
Composite Cost of Long-term Debt
($000's)

Docket No. E002/GR-19-564
Financial Information
Schedule A-1-LTD-1
Page 1 of 1

ACTUAL FISCAL YEAR 2018

										Total Bond Cost						
Description	Coupon Rate	Issue Date	Maturity Date	Amount	Premium or Hedge Gain/(Loss)	Bond Discount	Bond Expense	LRD Expense	2/ Capital Employed	Premium/ 3/ Interest Charge	Hedge Amortization	Discount Amortization	Expense Amortization	LRD Amortization	Cost of Capital	Capital Cost %
First Mortgage Bonds																
Series due July 1, 2025 (FMB)	7.1250	Jul-95	Jul-25	250,000	-	540	440		249,019	17,813	-	78	63		17,953	7.21%
Series due March 1, 2028 (FMB)	6.5000	Mar-98	Mar-28	150,000	-	565	473		148,962	9,750	-	59	49		9,858	6.62%
Series Due July 15, 2035 (FMB)	5.2500	Jul-05	Jul-35	250,000	-	275	1,719		248,006	13,125	-	16	101		13,242	5.34%
Series Due June 1, 2036 (FMB)	6.2500	May-06	Jun-36	400,000	9,741	836	2,905		406,000	25,000	545	47	162		24,665	6.08%
Series Due July 1, 2037 (FMB)	6.2000	Jun-07	Jul-37	350,000	-	1,256	2,740		346,005	21,700	-	66	144		21,911	6.33%
Series Due November 1, 2039 (FMB)	5.3500	Nov-09	Nov-39	300,000	(2,280)	405	2,953		294,362	16,050	(107)	19	139		16,315	5.54%
Series Due August 15, 2040 (FMB)	4.8500	Aug-10	Aug-40	250,000	-	521	2,222		247,258	12,125	-	24	101		12,249	4.95%
Series Due August 15, 2022 (FMB)	2.1500	Aug-12	Aug-22	300,000	-	186	1,262		298,552	6,450	-	46	309		6,805	2.28%
Series Due August 15, 2042 (FMB)	3.4000	Aug-12	Aug-42	500,000	(36,059)	3,066	5,037		455,838	17,000	(1,496)	127	209		18,833	4.13%
Series Due May 15, 2023 (FMB)	2.6000	May-13	May-23	400,000	-	354	2,190		397,456	10,400	-	73	453		10,927	2.75%
Series Due May 15, 2044 (FMB)	4.1250	May-14	May-44	300,000	-	751	3,292		295,957	12,375	-	29	127		12,531	4.23%
Series Due Aug 15, 2020 (FMB)	2.2000	Aug-15	Aug-20	300,000	-	229	1,282		298,489	6,600	-	110	616		7,326	2.45%
Series Due Aug 15, 2045 (FMB)	4.0000	Aug-15	Aug-45	300,000	-	4,420	3,519		292,060	12,000	-	163	130		12,293	4.21%
Series Due May 15, 2046 (FMB)	3.6000	May-16	May-46	350,000	-	1,944	5,024		343,031	12,600	-	70	180		12,850	3.75%
Series Due Sep 15, 2047 (FMB)	3.7000	Sep-17	Sep-47	600,000	-	5,814	8,553	8,140	577,493	22,200	-	199	268	279	22,946	3.97%
Other Debt																
Right of Way Notes	var	var	var	29	-	-	-		29	-	-	-	-		-	0.00%
TOTAL DEBT				5,000,029	(28,598)	21,163	43,611	8,140	4,898,517	215,188	(1,059)	1,125	3,052	279	220,702	4.51%
Unamortized Loss on Reacquired Debt									(10,467)						1,928	
Fees on 5-year Credit Facility 1/									-						456	
GRAND TOTAL and COST OF DEBT									4,888,050						223,086	4.56%

1/ Fees associated with the 5 Year Credit Facility are amortized over the life of the facility and are incorporated into the long-term debt rate.
2/ Capital Employed is based on the Premium / Discount / Expense Balances representing average declining balances. New and Maturing Debt averaged on number of months in the year.
3/ Interest Expense is a Straight Interest Expense calculation.

Northern States Power Company (Minnesota)
Regulated Electric Utility - State of Minnesota
RATE OF RETURN COST OF CAPITAL SCHEDULES
Composite Cost of Long-term Debt
($000's)

PROJECTED FISCAL YEAR 2019

Description	Coupon Rate	Issue Date	Maturity Date	Amount	Premium or Hedge Gain/(Loss	Bond Discount	Bond Expense	LRD Expense	(4) Capital Employed	Total Bond Cost: Premium/ (5) Interest Charge	Total Bond Cost: Hedge Amortization	Total Bond Cost: Discount Amortization	Total Bond Cost: Expense nortization	Total Bond Cost: LRD rtization	Cost of Capital	Capital Cost %
First Mortgage Bonds																
Series due July 1, 2025 (FMB)	7.1250	Jul-95	Jul-25	250,000	-	463	377		249,160	17,813	-	78	63		17,953	7.21%
Series due March 1, 2028 (FMB)	6.5000	Mar-98	Mar-28	150,000	-	506	424		149,070	9,750	-	59	49		9,858	6.61%
Series Due July 15, 2035 (FMB)	5.2500	Jul-05	Jul-35	250,000	-	259	1,618		248,123	13,125	-	16	101		13,242	5.34%
Series Due June 1, 2036 (FMB)	6.2500	May-06	Jun-36	400,000	9,196	789	2,742		405,664	25,000	(545)	47	162		25,754	6.35%
Series Due July 1, 2037 (FMB)	6.2000	Jun-07	Jul-37	350,000	-	1,189	2,595		346,215	21,700	-	66	144		21,911	6.33%
Series Due November 1, 2039 (FMB)	5.3500	Nov-09	Nov-39	300,000	(2,173)	386	2,815		294,627	16,050	107	19	139		16,101	5.46%
Series Due August 15, 2040 (FMB)	4.8500	Aug-10	Aug-40	250,000	-	497	2,121		247,382	12,125	-	24	101		12,249	4.95%
Series Due August 15, 2022 (FMB)	2.1500	Aug-12	Aug-22	300,000	-	140	953		298,907	6,450	-	46	309		6,805	2.28%
Series Due August 15, 2042 (FMB)	3.4000	Aug-12	Aug-42	500,000	(34,563)	2,938	4,828		457,671	17,000	1,496	127	209		15,840	3.46%
Series Due May 15, 2023 (FMB)	2.6000	May-13	May-23	400,000	-	281	1,737		397,983	10,400	-	73	453		10,927	2.75%
Series Due May 15, 2044 (FMB)	4.1250	May-14	May-44	300,000	-	722	3,164		296,113	12,375	-	29	127		12,531	4.23%
Series Due Aug 15, 2020 (FMB)	2.2000	Aug-15	Aug-20	300,000	-	119	666		299,215	6,600	-	110	616		7,326	2.45%
Series Due Aug 15, 2045 (FMB)	4.0000	Aug-15	Aug-45	300,000	-	4,257	3,389		292,353	12,000	-	163	130		12,293	4.20%
Series Due May 15, 2046 (FMB)	3.6000	May-16	May-46	350,000	-	1,875	4,844		343,282	12,600	-	70	180		12,850	3.74%
Series Due Sep 15, 2047 (FMB)	3.7000	Sep-17	Sep-47	600,000	-	5,615	8,261	7,861	578,263	22,200	-	199	293	279	22,971	3.97%
Series Due Mar 15, 2050 (FMB)	2.9000	Sep-19	Mar-50	200,000	-	-	2,980		197,020	5,800	-	-	98		5,898	2.99%
Other Debt																
Right of Way Notes	var	var	var	9	-	-	-		9	-	-	-	-		-	0.00%
TOTAL DEBT				5,200,009	(27,539)	20,038	43,514	7,861	5,101,057	220,988	1,059	1,125	3,176	279	224,509	4.40%
Unamortized Loss on Reacquired Debt									(8,575)						1,807	
Fees on 5-year Credit Facility (3)									-						412	
GRAND TOTAL and COST OF DEBT									5,092,482						226,727	4.45%

(1) NSPM 2019 issuance of $600M 30 year bond, balance is 4 of 12 months.
(2) Fees associated with the 5 Year Credit Facility are amortized over the life of the facility and are incorporated into the long-term debt rate.
(3) Capital Employed is based on the Premium / Discount / Expense Balances representing average declining balances. New and Maturing Debt averaged on number of months in the year.
(4) Interest Expense is a Straight Interest Expense calculation.

Northern States Power Company (Minnesota)
Regulated Electric Utility - State of Minnesota
RATE OF RETURN COST OF CAPITAL SCHEDULES
Composite Cost of Long-term Debt
($000's)

PROPOSED TEST YEAR 2020

										Total Bond Cost						
Description	**Coupon Rate**	**Issue Date**	**Maturity Date**	**Amount**	**Premium or Hedge Gain/(Loss**	**Bond Discount**	**Bond Expense**	**LRD Expense**	**(4) Capital Employed**	**Premium/ (5) Interest Charge**	**Hedge Amortization**	**Discount Amortization**	**Expense nortization**	**LRD ortization**	**Cost of Capital**	**Capital Cost %**
First Mortgage Bonds																
Series due July 1, 2025 (FMB)	7.1250	Jul-95	Jul-25	250,000	-	385	314		249,301	17,813	-	78	63		17,954	7.20%
Series due March 1, 2028 (FMB)	6.5000	Mar-98	Mar-28	150,000	-	448	375		149,178	9,750	-	59	49		9,858	6.61%
Series Due July 15, 2035 (FMB)	5.2500	Jul-05	Jul-35	250,000	-	243	1,517		248,241	13,125	-	16	101		13,243	5.33%
Series Due June 1, 2036 (FMB)	6.2500	May-06	Jun-36	400,000	8,650	742	2,580		405,328	25,000	(546)	47	163		25,756	6.35%
Series Due July 1, 2037 (FMB)	6.2000	Jun-07	Jul-37	350,000	-	1,123	2,451		346,426	21,700	-	66	145		21,911	6.32%
Series Due November 1, 2039 (FMB)	5.3500	Nov-09	Nov-39	300,000	(2,065)	367	2,676		294,892	16,050	107	19	139		16,101	5.46%
Series Due August 15, 2040 (FMB)	4.8500	Aug-10	Aug-40	250,000	-	473	2,020		247,506	12,125	-	24	101		12,249	4.95%
Series Due August 15, 2022 (FMB)	2.1500	Aug-12	Aug-22	300,000	-	95	643		299,262	6,450	-	46	310		6,806	2.27%
Series Due August 15, 2042 (FMB)	3.4000	Aug-12	Aug-42	500,000	(33,063)	2,811	4,618		459,508	17,000	1,501	128	210		15,837	3.45%
Series Due May 15, 2023 (FMB)	2.6000	May-13	May-23	400,000	-	207	1,282		398,511	10,400	-	73	455		10,928	2.74%
Series Due May 15, 2044 (FMB)	4.1250	May-14	May-44	300,000	-	693	3,037		296,270	12,375	-	29	128		12,532	4.23%
Series Due Aug 15, 2020 (FMB) (2)	2.2000	Aug-15	Aug-20	175,000	-	19	104		174,878	3,850	-	68	383		4,301	2.46%
Series Due Aug 15, 2045 (FMB)	4.0000	Aug-15	Aug-45	300,000	-	4,094	3,259		292,647	12,000	-	164	130		12,294	4.20%
Series Due May 15, 2046 (FMB)	3.6000	May-16	May-46	350,000	-	1,805	4,663		343,532	12,600	-	70	181		12,851	3.74%
Series Due Sep 15, 2047 (FMB)	3.7000	Sep-17	Sep-47	600,000	-	5,415	7,967	7,581	579,036	22,200	-	200	294	280	22,973	3.97%
Series Due Mar 15, 2050 (FMB)	2.9000	Sep-19	Mar-50	600,000	-	-	8,742		591,258	17,400	-	-	295		17,695	2.99%
Series Due Jun 1, 2050 (FMB) (1)	3.9000	Jun-20	Jun-50	495,833	-	-	7,355		488,479	19,338	-	-	249		19,587	4.01%
Other Debt																
Right of Way Notes	var	var	var	9	-	-	-		9	-	-	-	-		-	0.00%
TOTAL DEBT				5,970,843	(26,478)	18,919	53,601	7,581	5,864,263	249,175	1,062	1,086	3,396	280	252,875	4.31%
Unamortized Loss on Reacquired Debt									(6,950)						1,416	
Fees on 5-year Credit Facility (3)									-						380	
GRAND TOTAL and COST OF DEBT									5,857,314						254,671	4.35%

(1) NSPM 2020 issuance of $850M 30 year bond, balance is 7 of 12 months.
(2) NSPM 2015 issuance of $300M 5 year bond, balance is 7 of 12 months.
(3) Fees associated with the 5 Year Credit Facility are amortized over the life of the facility and are incorporated into the long-term debt rate.
(4) Capital Employed is based on the Premium / Discount / Expense Balances representing average declining balances. New and Maturing Debt averaged on number of months in the year.
(5) Interest Expense is a Straight Interest Expense calculation.

Northern States Power Company (Minnesota)
Consolidated
RATE OF RETURN COST OF CAPITAL SCHEDULES
Composite Cost of Long-term Debt
($000's)

ACTUAL FISCAL YEAR 2018

										Total Bond Cost						
					Premium or					Premium/						
Description	Coupon Rate	Issue Date	Maturity Date	Amount	Hedge Gain/(Loss)	Bond Discount	Bond Expense	LRD Expense	2/ Capital Employed	3/ Interest Charge	Hedge Amortization	Discount Amortization	Expense Amortization	LRD Amortization	Cost of Capital	Capital Cost %
First Mortgage Bonds																
Series due July 1, 2025 (FMB)	7.1250	Jul-95	Jul-25	250,000	-	540	440		249,019	17,813	-	78	63		17,953	7.21%
Series due March 1, 2028 (FMB)	6.5000	Mar-98	Mar-28	150,000	-	565	473		148,962	9,750	-	59	49		9,858	6.62%
Series Due July 15, 2035 (FMB)	5.2500	Jul-05	Jul-35	250,000	-	275	1,719		248,006	13,125	-	16	101		13,242	5.34%
Series Due June 1, 2036 (FMB)	6.2500	May-06	Jun-36	400,000	9,741	836	2,905		406,000	25,000	545	47	162		24,665	6.08%
Series Due July 1, 2037 (FMB)	6.2000	Jun-07	Jul-37	350,000	-	1,256	2,740		346,005	21,700	-	66	144		21,911	6.33%
Series Due November 1, 2039 (FMB)	5.3500	Nov-09	Nov-39	300,000	(2,280)	405	2,953		294,362	16,050	(107)	19	139		16,315	5.54%
Series Due August 15, 2040 (FMB)	4.8500	Aug-10	Aug-40	250,000	-	521	2,222		247,258	12,125	-	24	101		12,249	4.95%
Series Due August 15, 2022 (FMB)	2.1500	Aug-12	Aug-22	300,000	-	186	1,262		298,552	6,450	-	46	309		6,805	2.28%
Series Due August 15, 2042 (FMB)	3.4000	Aug-12	Aug-42	500,000	(36,059)	3,066	5,037		455,838	17,000	(1,496)	127	209		18,833	4.13%
Series Due May 15, 2023 (FMB)	2.6000	May-13	May-23	400,000	-	354	2,190		397,456	10,400	-	73	453		10,927	2.75%
Series Due May 15, 2044 (FMB)	4.1250	May-14	May-44	300,000	-	751	3,292		295,957	12,375	-	29	127		12,531	4.23%
Series Due Aug 15, 2020 (FMB)	2.2000	Aug-15	Aug-20	300,000	-	229	1,282		298,489	6,600	-	110	616		7,326	2.45%
Series Due Aug 15, 2045 (FMB)	4.0000	Aug-15	Aug-45	300,000	-	4,420	3,519		292,060	12,000	-	163	130		12,293	4.21%
Series Due May 15, 2046 (FMB)	3.6000	May-16	May-46	350,000	-	1,944	5,024		343,031	12,600	-	70	180		12,850	3.75%
Series Due Sep 15, 2047 (FMB)	3.7000	Sep-17	Sep-47	600,000	-	5,814	8,553	8,140	577,493	22,200	-	199	268	279	22,946	3.97%
Other Debt																
Right of Way Notes	var	var	var	29	-	-	-		29	-	-	-	-		-	0.00%
TOTAL DEBT				5,000,029	(28,598)	21,163	43,611	8,140	4,898,517	215,188	(1,059)	1,125	3,052	279	220,702	4.51%
Unamortized Loss on Reacquired Debt									(10,467)						1,928	
Fees on 5-year Credit Facility 1/									-						456	
GRAND TOTAL and COST OF DEBT									4,888,050						223,086	4.56%

1/ Fees associated with the 5 Year Credit Facility are amortized over the life of the facility and are incorporated into the long-term debt rate.

2/ Capital Employed is based on the Premium / Discount / Expense Balances representing average declining balances. New and Maturing Debt averaged on number of months in the year.

3/ Interest Expense is a Straight Interest Expense calculation.

Northern States Power Company (Minnesota)
Consolidated
RATE OF RETURN COST OF CAPITAL SCHEDULES
Composite Cost of Long-term Debt
($000's)

PROJECTED FISCAL YEAR 2019

Description	Coupon Rate	Issue Date	Maturity Date	Amount	Premium or Hedge Gain/(Loss)	Bond Discount	Bond Expense	LRD Expense	(4) Capital Employed	Total Bond Cost: (5) Interest Charge	Total Bond Cost: Premium/ Hedge Amortization	Total Bond Cost: Discount Amortization	Total Bond Cost: Expense Amortization	LRD Amortization	Cost of Capital	Capital Cost %
First Mortgage Bonds																
Series due July 1, 2025 (FMB)	7.1250	Jul-95	Jul-25	250,000	-	463	377		249,160	17,813	-	78	63		17,953	7.21%
Series due March 1, 2028 (FMB)	6.5000	Mar-98	Mar-28	150,000	-	506	424		149,070	9,750	-	59	49		9,858	6.61%
Series Due July 15, 2035 (FMB)	5.2500	Jul-05	Jul-35	250,000	-	259	1,618		248,123	13,125	-	16	101		13,242	5.34%
Series Due June 1, 2036 (FMB)	6.2500	May-06	Jun-36	400,000	9,196	789	2,742		405,664	25,000	(545)	47	162		25,754	6.35%
Series Due July 1, 2037 (FMB)	6.2000	Jun-07	Jul-37	350,000	-	1,189	2,595		346,215	21,700	-	66	144		21,911	6.33%
Series Due November 1, 2039 (FMB)	5.3500	Nov-09	Nov-39	300,000	(2,173)	386	2,815		294,627	16,050	107	19	139		16,101	5.46%
Series Due August 15, 2040 (FMB)	4.8500	Aug-10	Aug-40	250,000	-	497	2,121		247,382	12,125	-	24	101		12,249	4.95%
Series Due August 15, 2022 (FMB)	2.1500	Aug-12	Aug-22	300,000	-	140	953		298,907	6,450	-	46	309		6,805	2.28%
Series Due August 15, 2042 (FMB)	3.4000	Aug-12	Aug-42	500,000	(34,563)	2,938	4,828		457,671	17,000	1,496	127	209		15,840	3.46%
Series Due May 15, 2023 (FMB)	2.6000	May-13	May-23	400,000	-	281	1,737		397,983	10,400	-	73	453		10,927	2.75%
Series Due May 15, 2044 (FMB)	4.1250	May-14	May-44	300,000	-	722	3,164		296,113	12,375	-	29	127		12,531	4.23%
Series Due Aug 15, 2020 (FMB)	2.2000	Aug-15	Aug-20	300,000	-	119	666		299,215	6,600	-	110	616		7,326	2.45%
Series Due Aug 15, 2045 (FMB)	4.0000	Aug-15	Aug-45	300,000	-	4,257	3,389		292,353	12,000	-	163	130		12,293	4.20%
Series Due May 15, 2046 (FMB)	3.6000	May-16	May-46	350,000	-	1,875	4,844		343,282	12,600	-	70	180		12,850	3.74%
Series Due Sep 15, 2047 (FMB)	3.7000	Sep-17	Sep-47	600,000	-	5,615	8,261	7,861	578,263	22,200	-	199	293	279	22,971	3.97%
Series Due Mar 15, 2050 (FMB)	2.9000	Sep-19	Mar-50	200,000	-	-	2,980		197,020	5,800	-	-	98		5,898	2.99%
Other Debt																
Right of Way Notes	var	var	var	9	-	-	-		9	-	-	-	-		-	0.00%
TOTAL DEBT				5,200,009	(27,539)	20,038	43,514	7,861	5,101,057	220,988	1,059	1,125	3,176	279	224,509	4.40%
Unamortized Loss on Reacquired Debt									(8,575)						1,807	
Fees on 5-year Credit Facility (3)									-						412	
GRAND TOTAL and COST OF DEBT									5,092,482						226,727	4.45%

(1) NSPM 2019 issuance of $600M 30 year bond, balance is 4 of 12 months.

(2) Fees associated with the 5 Year Credit Facility are amortized over the life of the facility and are incorporated into the long-term debt rate.

(3) Capital Employed is based on the Premium / Discount / Expense Balances representing average declining balances. New and Maturing Debt averaged on number of months in the year.

(4) Interest Expense is a Straight Interest Expense calculation.

Northern States Power Company (Minnesota)
Consolidated
RATE OF RETURN COST OF CAPITAL SCHEDULES
Composite Cost of Long-term Debt
($000's)

PROPOSED TEST YEAR 2020

Description	Coupon Rate	Issue Date	Maturity Date	Amount	Premium or Hedge Gain/(Loss)	Bond Discount	Bond Expense	LRD Expense	(4) Capital Employed	Total Bond Cost: Premium/ (5) Interest Charge	Total Bond Cost: Hedge mortization	Total Bond Cost: Discount mortization	Total Bond Cost: Expense Amortization	LRD Amortization	Cost of Capital	Capital Cost %
First Mortgage Bonds																
Series due July 1, 2025 (FMB)	7.1250	Jul-95	Jul-25	250,000	-	385	314		249,301	17,813	-	78	63		17,954	7.20%
Series due March 1, 2028 (FMB)	6.5000	Mar-98	Mar-28	150,000	-	448	375		149,178	9,750	-	59	49		9,858	6.61%
Series Due July 15, 2035 (FMB)	5.2500	Jul-05	Jul-35	250,000	-	243	1,517		248,241	13,125	-	16	101		13,243	5.33%
Series Due June 1, 2036 (FMB)	6.2500	May-06	Jun-36	400,000	8,650	742	2,580		405,328	25,000	(546)	47	163		25,756	6.35%
Series Due July 1, 2037 (FMB)	6.2000	Jun-07	Jul-37	350,000	-	1,123	2,451		346,426	21,700	-	66	145		21,911	6.32%
Series Due November 1, 2039 (FMB)	5.3500	Nov-09	Nov-39	300,000	(2,065)	367	2,676		294,892	16,050	107	19	139		16,101	5.46%
Series Due August 15, 2040 (FMB)	4.8500	Aug-10	Aug-40	250,000	-	473	2,020		247,506	12,125	-	24	101		12,249	4.95%
Series Due August 15, 2022 (FMB)	2.1500	Aug-12	Aug-22	300,000	-	95	643		299,262	6,450	-	46	310		6,806	2.27%
Series Due August 15, 2042 (FMB)	3.4000	Aug-12	Aug-42	500,000	(33,063)	2,811	4,618		459,508	17,000	1,501	128	210		15,837	3.45%
Series Due May 15, 2023 (FMB)	2.6000	May-13	May-23	400,000	-	207	1,282		398,511	10,400	-	73	455		10,928	2.74%
Series Due May 15, 2044 (FMB)	4.1250	May-14	May-44	300,000	-	693	3,037		296,270	12,375	-	29	128		12,532	4.23%
Series Due Aug 15, 2020 (FMB) (2)	2.2000	Aug-15	Aug-20	175,000	-	19	104		174,878	3,850	-	68	383		4,301	2.46%
Series Due Aug 15, 2045 (FMB)	4.0000	Aug-15	Aug-45	300,000	-	4,094	3,259		292,647	12,000	-	164	130		12,294	4.20%
Series Due May 15, 2046 (FMB)	3.6000	May-16	May-46	350,000	-	1,805	4,663		343,532	12,600	-	70	181		12,851	3.74%
Series Due Sep 15, 2047 (FMB)	3.7000	Sep-17	Sep-47	600,000	-	5,415	7,967	7,581	579,036	22,200	-	200	294	280	22,973	3.97%
Series Due Mar 15, 2050 (FMB)	2.9000	Sep-19	Mar-50	600,000	-	-	8,742		591,258	17,400	-	-	295		17,695	2.99%
Series Due Jun 1, 2050 (FMB) (1)	3.9000	Jun-20	Jun-50	495,833	-	-	7,355		488,479	19,338	-	-	249		19,587	4.01%
Other Debt																
Right of Way Notes	var	var	var	9	-	-	-		9	-	-	-	-		-	0.00%
TOTAL DEBT				5,970,843	(26,478)	18,919	53,601	7,581	5,864,263	249,175	1,062	1,086	3,396	280	252,875	4.31%
Unamortized Loss on Reacquired Debt									(6,950)						1,416	
Fees on 5-year Credit Facility (3)									-						380	
GRAND TOTAL and COST OF DEBT									5,857,314						254,671	4.35%

(1) NSPM 2020 issuance of $850M 30 year bond, balance is 7 of 12 months.

(2) NSPM 2015 issuance of $300M 5 year bond, balance is 7 of 12 months.

(3) Fees associated with the 5 Year Credit Facility are amortized over the life of the facility and are incorporated into the long-term debt rate.

(4) Capital Employed is based on the Premium / Discount / Expense Balances representing average declining balances. New and Maturing Debt averaged on number of months in the year.

(5) Interest Expense is a Straight Interest Expense calculation.

Xcel Energy Inc. — **Docket No. E002/GR-19-564**
Consolidated — **Financial Information**
RATE OF RETURN COST OF CAPITAL SCHEDULES — **Schedule A-4-LTD-1**
Long-term Debt — **Page 1 of 2**
($000's)

MOST RECENT FISCAL YEAR 2018	**Actual 2018**	**Actual 2017**	**Average**	**Interest 2018**	**Weighted Average Interest 2018**
Northern States Power Company (Minnesota) Long-Term Debt					
First Mortgage Bonds, Series due:					
Aug. 15, 2020, 2.20%	300,000	300,000	300,000		
Aug. 15, 2022, 2.15%	300,000	300,000	300,000		
May 15, 2023, 2.60%	400,000	400,000	400,000		
July 1, 2025, 7.125%	250,000	250,000	250,000		
March 1, 2028, 6.5%	150,000	150,000	150,000		
Jul. 15, 2035, 5.25%	250,000	250,000	250,000		
Jun. 1, 2036, 6.25%	400,000	400,000	400,000		
Jul. 1, 2037, 6.20%	350,000	350,000	350,000		
Nov. 1, 2039, 5.35%	300,000	300,000	300,000		
Aug. 15, 2040, 4.85%	250,000	250,000	250,000		
Aug. 15, 2042, 3.40%	500,000	500,000	500,000		
May 15, 2044, 4.125%	300,000	300,000	300,000		
Aug 15, 2045, 4.00%	300,000	300,000	300,000		
May 15, 2046, 3.60%	350,000	350,000	350,000		
Sept 15, 2047, 3.60%	600,000	600,000	600,000		
Other	9	35	22		
Total	5,000,009	5,000,035	5,000,000		
Public Service Company of Colorado Long-Term Debt					
First Mortgage Bonds, Series due:					
Aug 1, 2018, 5.8%	0	300,000	150,000		
Jun. 1, 2019, 5.125%	400,000	400,000	400,000		
Nov. 15, 2020, 3.2%	400,000	400,000	400,000		
Sep. 15, 2022, 2.25%	300,000	300,000	300,000		
Mar. 15, 2023, 2.50%	250,000	250,000	250,000		
May 15, 2025, 2.90%	250,000	250,000	250,000		
Sep 1, 2037, 6.25%	350,000	350,000	350,000		
Aug. 1, 2038, 6.5%	300,000	300,000	300,000		
Aug. 15, 2041, 4.75%	250,000	250,000	250,000		
Sep. 15, 2042, 3.60%	500,000	500,000	500,000		
Mar. 15, 2043, 3.95%	250,000	250,000	250,000		
Mar. 15, 2044, 4.30%	300,000	300,000	300,000		
Jun 15, 2046, 3.55%	250,000	250,000	250,000		
Jun 15, 2047, 3.80%	400,000	400,000	400,000		
Jun 15, 2028, 3.70%	350,000	0	175,000		
Jun 15, 2048, 4.10%	350,000	0	175,000		
Total	4,900,000	4,500,000	4,700,000		
Southwestern Public Service Company Long-Term Debt					
First Mortgage Bonds, Series due:					
June 15, 2024, 3.30%	350,000	350,000	350,000		
Aug 15, 2041, 4.50%	400,000	400,000	400,000		
Aug 15, 2046, 3.40%	300,000	300,000	300,000		
Aug 15, 2047, 3.70%	450,000	450,000	450,000		
Nov 15, 2048, 4.40%	300,000	0	150,000		
Unsecured Senior C and D Notes, due Oct. 1, 2033, 6.0%	100,000	100,000	100,000		
Unsecured Senior F Notes, due Oct. 1, 2036, 6.0%	250,000	250,000	250,000		
Total	2,150,000	1,850,000	2,000,000		

Xcel Energy Inc. — **Docket No. E002/GR-19-564**
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RATE OF RETURN COST OF CAPITAL SCHEDULES — **Schedule A-4-LTD-1**
Long-term Debt — **Page 2 of 2**
($000's)

Northern States Power Company (Wisconsin) Long-Term Debt	**Actual 2018**	**Actual 2017**	**Average**	**Interest 2018**	**Weighted Average Interest 2018**
First Mortgage Bonds Series due:					
Oct. 1, 2018, 5.25%	0	150,000	75,000		
June 15, 2024, 3.30%	200,000	200,000	200,000		
Sep 1, 2038, 6.375%	200,000	200,000	200,000		

Oct 1, 2042, 3.70%	100,000	100,000	100,000		
Dec 1, 2047, 3.75%	100,000	100,000	100,000		
Sep 1, 2048, 4.20%	200,000	0	100,000		
City of La Crosse Resource Recovery Bond – Series due Nov. 1, 2021, 6%	18,600	18,600	18,600		
Fort McCoy System Acquisition - due Oct. 31, 2030, 7%	389	1,468	928		
Other - Clearwater Investments	486	486	486		
Total	819,475	770,554	795,014		
Other Subsidiaries' Long-Term Debt					
Various Eloigne Co. Affordable Housing Project Notes due 2018 - 2052, 0% -	26,670	28,424	27,547		
Total	26,670	28,424	27,547		
Xcel Energy Inc. Debt					
Unsecured Senior Notes, Series due:					
May 15, 2020, 4.70%	550,000	550,000	550,000		
Mar 15, 2021, 2.40%	400,000	400,000	400,000		
Mar 15, 2022, 2.60%	300,000	300,000	300,000		
Jun 1, 2025, 3.30%	600,000	600,000	600,000		
Dec 1, 2026, 3.35%	500,000	500,000	500,000		
Jul 1, 2036, 6.50%	300,000	300,000	300,000		
Sep 15, 2041, 4.80%	250,000	250,000	250,000		
Jun 15, 2028, 4.00%	500,000	0	250,000		
Total Xcel Energy Inc. debt	3,400,000	2,900,000	3,150,000		
Total long-term debt	16,296,154	15,049,013	15,672,561	$653,180	
Debt Discount, Debt Expense & Loss on Reacquired Debt			(217,259) **1/**	$21,306 **2/**	
Total Including Debt Discount, Debt Expense and Loss on Reacquired Debt			15,455,302	674,487	4.36%

1/ Unamortized balance of debt discount, debt expense and loss of reacquired debt represents average balance @ 12/31/18 & 12/31/17
2/ Includes fees on 5-year credit facility (long-term for GAAP purposes)

Xcel Energy Inc.
Consolidated
RATE OF RETURN COST OF CAPITAL SCHEDULES
Long-term Debt
($000's)

Docket No. E002/GR-19-564
Financial Information
Schedule A-4-LTD-2

PROJECTED FISCAL YEAR 2019 1/

Northern States Power Company (Minnesota) Long-Term Debt	Projected 2019	Actual 2018	Average	Interest 2019	Weighted Average Interest 2019
First Mortgage Bonds, Series due:					
Aug. 15, 2020, 2.20%	300,000	300,000	300,000		
Aug. 15, 2022, 2.15%	300,000	300,000	300,000		
May 15, 2023, 2.60%	400,000	400,000	400,000		
July 1, 2025, 7.125%	250,000	250,000	250,000		
March 1, 2028, 6.5%	150,000	150,000	150,000		
Jul. 15, 2035, 5.25%	250,000	250,000	250,000		
Jun. 1, 2036, 6.25%	400,000	400,000	400,000		
Jul. 1, 2037, 6.20%	350,000	350,000	350,000		
Nov. 1, 2039, 5.35%	300,000	300,000	300,000		
Aug. 15, 2040, 4.85%	250,000	250,000	250,000		
Aug. 15, 2042, 3.40%	500,000	500,000	500,000		
May 15, 2044, 4.125%	300,000	300,000	300,000		
Aug 15, 2045, 4.00%	300,000	300,000	300,000		
May 15, 2046, 3.60%	350,000	350,000	350,000		
Sept 15, 2047, 3.60%	600,000	600,000	600,000		
Mar 1, 2050, 2.90%	600,000	0	300,000		
Other	9	9	9		
Total	5,600,009	5,000,009	5,300,009		

Public Service Company of Colorado Long-Term Debt	Projected 2019	Actual 2018	Average
First Mortgage Bonds, Series due:			
Jun. 1, 2019, 5.125%	0	400,000	200,000
Nov. 15, 2020, 3.2%	400,000	400,000	400,000
Sep. 15, 2022, 2.25%	300,000	300,000	300,000
Mar. 15, 2023, 2.50%	250,000	250,000	250,000
May 15, 2025, 2.90%	250,000	250,000	250,000
Sep 1, 2037, 6.25%	350,000	350,000	350,000
Aug. 1, 2038, 6.5%	300,000	300,000	300,000
Aug. 15, 2041, 4.75%	250,000	250,000	250,000
Sep. 15, 2042, 3.60%	500,000	500,000	500,000
Mar. 15, 2043, 3.95%	250,000	250,000	250,000
Mar. 15, 2044, 4.30%	300,000	300,000	300,000
Jun 15, 2046, 3.55%	250,000	250,000	250,000
Jun 15, 2047, 3.80%	400,000	400,000	400,000
Jun 15, 2028, 3.70%	350,000	350,000	350,000
Jun 15, 2048, 4.10%	350,000	350,000	350,000
Sep 15, 2049, 4.05%	400,000	0	200,000
Mar 1, 2050, 3.20%	550,000	0	275,000
Total	5,450,000	4,900,000	5,175,000

Southwestern Public Service Company Long-Term Debt	Projected 2019	Actual 2018	Average
First Mortgage Bonds, Series due:			
June 15, 2024, 3.30%	350,000	350,000	350,000
Aug 15, 2041, 4.50%	400,000	400,000	400,000
Aug 15, 2046, 3.40%	300,000	300,000	300,000
Aug 15, 2047, 3.70%	450,000	450,000	450,000
Nov 15, 2048, 4.40%	300,000	300,000	300,000
Jun 15, 2049, 3.75%	300,000	0	150,000
Unsecured Senior C and D Notes, due Oct. 1, 2033, 6.0%	100,000	100,000	100,000
Unsecured Senior F Notes, due Oct. 1, 2036, 6.0%	250,000	250,000	250,000
Total	2,450,000	2,150,000	2,300,000

Xcel Energy Inc.
Consolidated
RATE OF RETURN COST OF CAPITAL SCHEDULES
Long-term Debt
($000's)

Docket No. E002/GR-19-564
Financial Information
Schedule A-4-LTD-2

Northern States Power Company (Wisconsin) Long-Term Debt	Projected 2019	Actual 2018	Average	Interest 2019	Weighted Average Interest 2019
First Mortgage Bonds Series due:					
June 15, 2024, 3.30%	200,000	200,000	200,000		
June 15 2024, 3.30% - Reopener	200,000	200,000	200,000		
Sep 1, 2038, 6.375%	100,000	100,000	100,000		
Oct 1, 2042, 3.70%	100,000	100,000	100,000		

Dec 1, 2047, 3.75%	200,000	200,000	200,000		
City of La Crosse Resource Recovery Bond – Series due Nov. 1, 2021, 6%	18,600	18,600	18,600		
Fort McCoy System Acquisition - due Oct. 31, 2030, 7%	355	389	372		
Other - Clearwater Investments	486	486	486		
Total	819,441	819,475	819,458		
Other Subsidiaries' Long-Term Debt					
Various Eloigne Co. Affordable Housing Project Notes due 2018 - 2052, 0% -	25,148	26,670	25,909		
Total	25,148	26,670	25,909		
Xcel Energy Inc. Debt					
Unsecured Senior Notes, Series due:					
May 15, 2020, 4.70%	550,000	550,000	550,000		
Mar 15, 2021, 2.40%	400,000	400,000	400,000		
Mar 15, 2022, 2.60%	300,000	300,000	300,000		
Jun 1, 2025, 3.30%	600,000	600,000	600,000		
Dec 1, 2026, 3.35%	500,000	500,000	500,000		
Jul 1, 2036, 6.50%	300,000	300,000	300,000		
Sep 15, 2041, 4.80%	250,000	250,000	250,000		
Jun 15, 2028, 4.00%	630,000	500,000	565,000		
Nov 1, 2049, 3.60%	500,000	0	250,000		
Total Xcel Energy Inc. debt	4,030,000	3,400,000	3,715,000		
Total long-term debt	18,374,597	16,296,154	17,335,375	$716,168	
Debt Discount, Debt Expense & Loss on Reacquired Debt			(236,553)	20,411 **1/**	
Total Including Debt Discount, Debt Expense and Loss on Reacquired Debt			17,098,823	736,579	4.31%

1/ Includes 5-year Credit Facility Up Front Fees (long-term for GAAP purposes)

Xcel Energy Inc. | **Docket No. E002/GR-19-564**
Consolidated | **Financial Information**
RATE OF RETURN COST OF CAPITAL SCHEDULES | **Schedule A-4-LTD-3**
Long-term Debt |
($000's)

PROJECTED FISCAL YEAR 2020

Northern States Power Company (Minnesota) Long-Term Debt	**Projected 2020**	**Projected 2019**	**Average**	**Interest 2020**	**Weighted Average Interest 2020**
First Mortgage Bonds, Series due:					
Aug. 15, 2020, 2.20%	0	300,000	150,000		
Aug. 15, 2022, 2.15%	300,000	300,000	300,000		
May 15, 2023, 2.60%	400,000	400,000	400,000		
July 1, 2025, 7.125%	250,000	250,000	250,000		
March 1, 2028, 6.5%	150,000	150,000	150,000		
Jul. 15, 2035, 5.25%	250,000	250,000	250,000		
Jun. 1, 2036, 6.25%	400,000	400,000	400,000		
Jul. 1, 2037, 6.20%	350,000	350,000	350,000		
Nov. 1, 2039, 5.35%	300,000	300,000	300,000		
Aug. 15, 2040, 4.85%	250,000	250,000	250,000		
Aug. 15, 2042, 3.40%	500,000	500,000	500,000		
May 15, 2044, 4.125%	300,000	300,000	300,000		
Aug 15, 2045, 4.00%	300,000	300,000	300,000		
May 15, 2046, 3.60%	350,000	350,000	350,000		
Sept 15, 2047, 3.60%	600,000	600,000	600,000		
Mar 1, 2050, 2.90%	600,000	600,000	600,000		
Jun 1, 2050, 3.40%	850,000	0	425,000		
Other	9	9	9		
Total	6,150,009	5,600,009	5,875,009		

Public Service Company of Colorado Long-Term Debt					
First Mortgage Bonds, Series due:					
Nov. 15, 2020, 3.2%	0	400,000	200,000		
Sep. 15, 2022, 2.25%	300,000	300,000	300,000		
Mar. 15, 2023, 2.50%	250,000	250,000	250,000		
May 15, 2025, 2.90%	250,000	250,000	250,000		
Sep 1, 2037, 6.25%	350,000	350,000	350,000		
Aug. 1, 2038, 6.5%	300,000	300,000	300,000		
Aug. 15, 2041, 4.75%	250,000	250,000	250,000		
Sep. 15, 2042, 3.60%	500,000	500,000	500,000		
Mar. 15, 2043, 3.95%	250,000	250,000	250,000		
Mar. 15, 2044, 4.30%	300,000	300,000	300,000		
Jun 15, 2046, 3.55%	250,000	250,000	250,000		
Jun 15, 2047, 3.80%	400,000	400,000	400,000		
Jun 15, 2028, 3.70%	350,000	350,000	350,000		
Jun 15, 2048, 4.10%	350,000	350,000	350,000		
Sep 15, 2049, 4.05%	400,000	400,000	400,000		
Mar 1, 2050, 3.20%	550,000	550,000	550,000		
Sep 1, 2050, 3.70%	750,000	0	375,000		
	5,800,000	5,450,000	5,625,000		

Southwestern Public Service Company Long-Term Debt					
First Mortgage Bonds, Series due:					
June 15, 2024, 3.30%	350,000	350,000	350,000		
Aug 15, 2041, 4.50%	400,000	400,000	400,000		
Aug 15, 2046, 3.40%	300,000	300,000	300,000		
Aug 15, 2047, 3.70%	450,000	450,000	450,000		
Nov 15, 2048, 4.40%	300,000	300,000	300,000		
Jun 15, 2049, 3.75%	300,000	300,000	300,000		
May 1, 2050, 3.60%	300,000	0	150,000		
Unsecured Senior C and D Notes, due Oct. 1, 2033, 6.0%	100,000	100,000	100,000		
Unsecured Senior F Notes, due Oct. 1, 2036, 6.0%	250,000	250,000	250,000		
Total	2,750,000	2,450,000	2,600,000		

Xcel Energy Inc. | **Docket No. E002/GR-19-564**
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RATE OF RETURN COST OF CAPITAL SCHEDULES | **Schedule A-4-LTD-3**
Long-term Debt |
($000's)
Weighted
Average

Northern States Power Company (Wisconsin) Long-Term Debt	Projected 2020	Projected 2019	Average	Interest 2020	Interest 2020
First Mortgage Bonds Series due:					
June 15, 2024, 3.30%	200,000	200,000	200,000		
June 15 2024, 3.30% - Reopener	200,000	200,000	200,000		
Sep 1, 2038, 6.375%	100,000	100,000	100,000		
Oct 1, 2042, 3.70%	100,000	100,000	100,000		
Dec 1, 2047, 3.75%	200,000	200,000	200,000		
Jun 1, 2050, 3.40%	100,000	0	50,000		
City of La Crosse Resource Recovery Bond – Series due Nov. 1, 2021, 6%	18,600	18,600	18,600		
Fort McCoy System Acquisition - due Oct. 31, 2030, 7%	321	355	338		
Other - Clearwater Investments	486	486	486		
Total	919,407	819,441	869,424		
Other Subsidiaries' Long-Term Debt					
Various Eloigne Co. Affordable Housing Project Notes due 2018 - 2052, 0% -	25,148	25,148	25,148		
Total	25,148	25,148	25,148		
Xcel Energy Inc. Debt					
Unsecured Senior Notes, Series due:					
May 15, 2020, 4.70%	0	550,000	275,000		
Mar 15, 2021, 2.40%	400,000	400,000	400,000		
Mar 15, 2022, 2.60%	300,000	300,000	300,000		
Jun 1, 2025, 3.30%	600,000	600,000	600,000		
Dec 1, 2026, 3.35%	500,000	500,000	500,000		
Jul 1, 2036, 6.50%	300,000	300,000	300,000		
Sep 15, 2041, 4.80%	250,000	250,000	250,000		
Jun 15, 2028, 4.00%	630,000	630,000	630,000		
Nov 1, 2049, 3.60%	500,000	500,000	500,000		
Mar 1, 2030, 3.00%	900,000	0	450,000		
Nov 1, 2030, 3.40%	500,000	0	250,000		
Total Xcel Energy Inc. debt	4,880,000	4,030,000	4,455,000		
Total long-term debt	20,524,563	18,374,597	19,449,580	$798,566	
Debt Discount, Debt Expense & Loss on Reacquired Debt			(262,169)	$21,679 **1/**	
Total Including Debt Discount, Debt Expense and Loss on Reacquired Debt			19,187,411	820,245	4.27%

1/ Includes fees on 5-year credit facility (long-term for GAAP purposes)

($000's)

2020 FORECASTED LONG TERM DEBT AND COST

Description	Coupon Rate	Issue Date	Maturity Date	Amount	Premium or Hedge Gain/(Loss)	Bond Discount	Bond Expense	LRD Expense	(4) Capital Employed	Total Bond Cost (5) Interest Charge	Premium/ Hedge Amortization	Discount Amortization	Expense Amortization	LRD Amortization	Cost of Capital	Capital Cost %
First Mortgage Bonds																
Series due July 1, 2025 (FMB)	7.1250	Jul-95	Jul-25	250,000	-	385	314		249,301	17,813	-	78	63		17,954	7.20%
Series due March 1, 2028 (FMB)	6.5000	Mar-98	Mar-28	150,000	-	448	375		149,178	9,750	-	59	49		9,858	6.61%
Series Due July 15, 2035 (FMB)	5.2500	Jul-05	Jul-35	250,000	-	243	1,517		248,241	13,125	-	16	101		13,243	5.33%
Series Due June 1, 2036 (FMB)	6.2500	May-06	Jun-36	400,000	8,650	742	2,580		405,328	25,000	(546)	47	163		25,756	6.35%
Series Due July 1, 2037 (FMB)	6.2000	Jun-07	Jul-37	350,000	-	1,123	2,451		346,426	21,700	-	66	145		21,911	6.32%
Series Due November 1, 2039 (FMB)	5.3500	Nov-09	Nov-39	300,000	(2,065)	367	2,676		294,892	16,050	107	19	139		16,101	5.46%
Series Due August 15, 2040 (FMB)	4.8500	Aug-10	Aug-40	250,000	-	473	2,020		247,506	12,125	-	24	101		12,249	4.95%
Series Due August 15, 2022 (FMB)	2.1500	Aug-12	Aug-22	300,000	-	95	643		299,262	6,450	-	46	310		6,806	2.27%
Series Due August 15, 2042 (FMB)	3.4000	Aug-12	Aug-42	500,000	(33,063)	2,811	4,618		459,508	17,000	1,501	128	210		15,837	3.45%
Series Due May 15, 2023 (FMB)	2.6000	May-13	May-23	400,000	-	207	1,282		398,511	10,400	-	73	455		10,928	2.74%
Series Due May 15, 2044 (FMB)	4.1250	May-14	May-44	300,000	-	693	3,037		296,270	12,375	-	29	128		12,532	4.23%
Series Due Aug 15, 2020 (FMB) (2)	2.2000	Aug-15	Aug-20	175,000	-	19	104		174,878	3,850	-	68	383		4,301	2.46%
Series Due Aug 15, 2045 (FMB)	4.0000	Aug-15	Aug-45	300,000	-	4,094	3,259		292,647	12,000	-	164	130		12,294	4.20%
Series Due May 15, 2046 (FMB)	3.6000	May-16	May-46	350,000	-	1,805	4,663		343,532	12,600	-	70	181		12,851	3.74%
Series Due Sep 15, 2047 (FMB)	3.7000	Sep-17	Sep-47	600,000	-	5,415	7,967	7,581	579,036	22,200	-	200	294	280	22,973	3.97%
Series Due Mar 15, 2050 (FMB)	2.9000	Sep-19	Mar-50	600,000	-	-	8,742		591,258	17,400	-	-	295		17,695	2.99%
Series Due Jun 1, 2050 (FMB) (1)	3.9000	Jun-20	Jun-50	495,833	-	-	7,355		488,479	19,338	-	-	249		19,587	4.01%
Other Debt																
Right of Way Notes	var	var	var	9	-	-	-		9	-	-	-	-		-	0.00%
TOTAL DEBT				5,970,843	(26,478)	18,919	53,601	7,581	5,864,263	249,175	1,062	1,086	3,396	280	252,875	4.31%
Unamortized Loss on Reacquired Debt									(6,950)						1,416	
Fees on 5-year Credit Facility (3)									-						380	
GRAND TOTAL and COST OF DEBT									5,857,314						254,671	4.35%

(1) NSPM 2020 issuance of $850M 30 year bond, balance is 7 of 12 months.

(2) NSPM 2015 issuance of $300M 5 year bond, balance is 7 of 12 months.

(3) Fees associated with the 5 Year Credit Facility are amortized over the life of the facility and are incorporated into the long-term debt rate.

(4) Capital Employed is based on the Premium / Discount / Expense Balances representing average declining balances. New and Maturing Debt averaged on number of months in the year.

(5) Interest Expense is a Straight Interest Expense calculation.

Northern States Power Company
Electric Utility - State of Minnesota
RATE OF RETURN COST OF CAPITAL SCHEDULES
Composite Cost of Long-Term Debt
($000's)

Docket No. E002/GR-19-564
Vol. 3 Required Information

2021 FORECASTED LONG TERM DEBT AND COST

Description	Coupon Rate	Issue Date	Maturity Date	Amount	Premium or Hedge Gain/(Loss)	Bond Discount	Bond Expense	LRD Expense	(3) Capital Employed	Total Bond Cost						Capital Cost %
										(4) Interest Charge	Premium/ Hedge Amortization	Discount Amortization	Expense Amortization	LRD Amortization	Cost of Capital	
First Mortgage Bonds																
Series due July 1, 2025 (FMB)	7.1250	Jul-95	Jul-25	250,000	-	307	250		249,442	17,813	-	78	63		17,953	7.20%
Series due March 1, 2028 (FMB)	6.5000	Mar-98	Mar-28	150,000	-	389	326		149,285	9,750	-	59	49		9,858	6.60%
Series Due July 15, 2035 (FMB)	5.2500	Jul-05	Jul-35	250,000	-	226	1,416		248,358	13,125	-	16	101		13,242	5.33%
Series Due June 1, 2036 (FMB)	6.2500	May-06	Jun-36	400,000	8,106	696	2,417		404,993	25,000	(545)	47	162		25,754	6.36%
Series Due July 1, 2037 (FMB)	6.2000	Jun-07	Jul-37	350,000	-	1,057	2,306		346,637	21,700	-	66	144		21,911	6.32%
Series Due November 1, 2039 (FMB)	5.3500	Nov-09	Nov-39	300,000	(1,958)	348	2,537		295,156	16,050	107	19	139		16,101	5.45%
Series Due August 15, 2040 (FMB)	4.8500	Aug-10	Aug-40	250,000	-	450	1,920		247,630	12,125	-	24	101		12,249	4.95%
Series Due August 15, 2022 (FMB)	2.1500	Aug-12	Aug-22	300,000	-	49	334		299,617	6,450	-	46	309		6,805	2.27%
Series Due August 15, 2042 (FMB)	3.4000	Aug-12	Aug-42	500,000	(31,566)	2,684	4,409		461,341	17,000	1,496	127	209		15,840	3.43%
Series Due May 15, 2023 (FMB)	2.6000	May-13	May-23	400,000	-	134	829		399,037	10,400	-	73	453		10,927	2.74%
Series Due May 15, 2044 (FMB)	4.1250	May-14	May-44	300,000	-	664	2,909		296,427	12,375	-	29	127		12,531	4.23%
Series Due Aug 15, 2045 (FMB)	4.0000	Aug-15	Aug-45	300,000	-	3,931	3,129		292,940	12,000	-	163	130		12,293	4.20%
Series Due May 15, 2046 (FMB)	3.6000	May-16	May-46	350,000	-	1,735	4,482		343,783	12,600	-	70	180		12,850	3.74%
Series Due Sep 15, 2047 (FMB)	3.7000	Sep-17	Sep-47	600,000	-	5,216	7,674	7,302	579,808	22,200	-	199	293	279	22,971	3.96%
Series Due Mar 15, 2050 (FMB)	2.9000	Sep-19	Mar-50	600,000	-	-	8,447		591,553	17,400	-	-	295		17,695	2.99%
Series Due Jun 1, 2050 (FMB)	3.9000	Jun-20	Jun-50	850,000	-	-	12,272		837,728	33,150	-	-	425		33,575	4.01%
Series Due May 1, 2051 (FMB) (1)	4.1000	May-21	May-51	233,333	-	-	3,456		229,877	9,567	-	-	117		9,684	4.21%
Other Debt																
Right of Way Notes	var	var	var	9	-	-	-		9	-	-	-	-		-	0.00%
TOTAL DEBT				6,383,343	(25,419)	17,885	59,113	7,302	6,273,623	268,704	1,059	1,015	3,298	279	272,238	4.34%
Unamortized Loss on Reacquired Debt									(5,700)						1,217	
Fees on 5-year Credit Facility (2)									-						379	
GRAND TOTAL and COST OF DEBT									6,267,923						273,833	$\boxed{4.37\%}$

(1) NSPM 2021 issuance of $350M 30 year bond, balance is 8 of 12 months.

(2) Fees associated with the 5 Year Credit Facility are amortized over the life of the facility and are incorporated into the long-term debt rate.

(3) Capital Employed is based on the Premium / Discount / Expense Balances representing average declining balances. New and Maturing Debt averaged on number of months in the year.

(4) Interest Expense is a Straight Interest Expense calculation.

($000's)

2022 FORECASTED LONG TERM DEBT AND COST

Description	Coupon Rate	Issue Date	Maturity Date	Amount	Premium or Hedge Gain/(Loss)	Bond Discount	Bond Expense	LRD Expense	(4) Capital Employed	Total Bond Cost: (5) Interest Charge	Premium/ Hedge Amortization	Discount Amortization	Expense Amortization	LRD Amortization	Cost of Capital	Capital Cost %
First Mortgage Bonds																
Series due July 1, 2025 (FMB)	7.1250	Jul-95	Jul-25	250,000	-	230	187		249,583	17,813	-	78	63		17,953	7.19%
Series due March 1, 2028 (FMB)	6.5000	Mar-98	Mar-28	150,000	-	330	277		149,393	9,750	-	59	49		9,858	6.60%
Series Due July 15, 2035 (FMB)	5.2500	Jul-05	Jul-35	250,000	-	210	1,314		248,475	13,125	-	16	101		13,242	5.33%
Series Due June 1, 2036 (FMB)	6.2500	May-06	Jun-36	400,000	7,561	649	2,255		404,657	25,000	(545)	47	162		25,754	6.36%
Series Due July 1, 2037 (FMB)	6.2000	Jun-07	Jul-37	350,000	-	991	2,162		346,848	21,700	-	66	144		21,911	6.32%
Series Due November 1, 2039 (FMB)	5.3500	Nov-09	Nov-39	300,000	(1,851)	329	2,398		295,421	16,050	107	19	139		16,101	5.45%
Series Due August 15, 2040 (FMB)	4.8500	Aug-10	Aug-40	250,000	-	426	1,819		247,754	12,125	-	24	101		12,249	4.94%
Series Due August 15, 2022 (FMB) (2)	2.1500	Aug-12	Aug-22	175,000	-	8	52		174,940	3,763	-	28	191		3,982	2.28%
Series Due August 15, 2042 (FMB)	3.4000	Aug-12	Aug-42	500,000	(30,069)	2,556	4,200		463,174	17,000	1,496	127	209		15,840	3.42%
Series Due May 15, 2023 (FMB)	2.6000	May-13	May-23	400,000	-	61	375		399,564	10,400	-	73	453		10,927	2.73%
Series Due May 15, 2044 (FMB)	4.1250	May-14	May-44	300,000	-	635	2,782		296,583	12,375	-	29	127		12,531	4.23%
Series Due Aug 15, 2045 (FMB)	4.0000	Aug-15	Aug-45	300,000	-	3,767	2,999		293,233	12,000	-	163	130		12,293	4.19%
Series Due May 15, 2046 (FMB)	3.6000	May-16	May-46	350,000	-	1,665	4,302		344,033	12,600	-	70	180		12,850	3.74%
Series Due Sep 15, 2047 (FMB)	3.7000	Sep-17	Sep-47	600,000	-	5,017	7,381	7,023	580,579	22,200	-	199	293	279	22,971	3.96%
Series Due Mar 15, 2050 (FMB)	2.9000	Sep-19	Mar-50	600,000	-	-	8,153		591,847	17,400	-	-	295		17,695	2.99%
Series Due Jun 1, 2050 (FMB)	3.9000	Jun-20	Jun-50	850,000	-	-	11,847		838,153	33,150	-	-	425		33,575	4.01%
Series Due May 1, 2051 (FMB)	4.1000	May-21	May-51	350,000	-	-	5,038		344,962	14,350	-	-	175		14,525	4.21%
Series Due Jun 1, 2052 (FMB) (1)	4.6000	Jun-22	Jun-52	291,667	-	-	4,326		287,340	13,417	-	-	146		13,563	4.72%
Other Debt																
Right of Way Notes	var	var	var	9	-	-	-		9	-	-	-	-		-	0.00%
TOTAL DEBT				6,666,676	(24,360)	16,874	61,868	7,023	6,556,550	284,217	1,059	998	3,385	279	287,819	4.39%
Unamortized Loss on Reacquired Debt									(4,529)						1,020	
Fees on 5-year Credit Facility (3)									-						379	
GRAND TOTAL and COST OF DEBT									6,552,021						289,218	4.41%

(1) NSPM 2022 issuance of $500M 30 year bond, balance is 7 of 12 months.

(2) NSPM 2012 issuance of $300M 10 year bond, balance is 7 of 12 months.

(3) Fees associated with the 5 Year Credit Facility are amortized over the life of the facility and are incorporated into the long-term debt rate.

(4) Capital Employed is based on the Premium / Discount / Expense Balances representing average declining balances. New and Maturing Debt averaged on number of months in the year.

(5) Interest Expense is a Straight Interest Expense calculation.

Twelve-month Average

	Average Net Proceeds 1/	Interest Cost: Total 12 Month Interest Expense 2/	Average Interest Cost	Financing Charge: Total 12 Month Financing Charge 2/	Average Interest Cost	Average Capital Cost
	(A)	(B)	(C)	(D)	(E)	(F)
			(B) / (A)		(D) / (A)	(C)+ (F)
MOST RECENT FISCAL YEAR 2018						
Short-term borrowings 3/	$ 51,086,820	$ 1,044,340	2.04%	$ 471,197	0.91%	2.97%
Direct Borrowings under 5-year credit facilit	$ -	$ -	0.00%	$ -	0.00%	0.00%
Weighted Cost	$ 51,086,820	$ 1,044,340	2.04%	$ 471,197	0.92%	2.97%
PROJECTED FISCAL YEAR 2019						
Short-term borrowings 3/	$181,912,550	$4,449,409	2.45%	$484,024	0.27%	2.71%
Direct Borrowings under 5-year credit facilit	$ -	$ -	0.00%	$ -	0.00%	0.00%
Weighted Cost	$ 181,912,550	$ 4,449,409	2.45%	$ 484,024	0.27%	2.71%
PROPOSED TEST YEAR YEAR 2020						
Short-term borrowings 3/	$109,642,230	$2,753,784	2.51%	$503,847	0.46%	2.97%
Direct Borrowings under 5-year credit facilit	$ -	$ -	0.00%	$ -	0.00%	0.00%
Weighted Cost	$ 109,642,230	$ 2,753,784	2.51%	$ 503,847	0.46%	2.97%

1/ Actuals are 12 month average of average daily balances.
Forecast are 12 month average of current and prior month -end average.

2/ Includes interest expense on short term debt and finance charges associated with the June 2016 and June 2019 five year credit facility. The finance charges represent the monthly cost of NSP-MN unused portion of the credit facility which is primarily used for commercial paper back and letters of credit.

3/ Based on simple average of net proceeds average balances.

4/ Direct Borrowings from the 5-year credit facility are shown as a separate line item.
Upfront fees related to the 5-year credit facility are included in the long-term debt cost and amortized over the life of the credit facility.

Twelve-month Average

Month	Short Term Debt NSP-Minnesota 1/
MOST RECENT FISCAL YEAR 2018	
2018 Jan	$189,000,000
Feb	$83,000,000
Mar	$0
Apr	$0
May	$0
Jun	$62,000,000
Jul	$99,000,000
Aug	$23,000,000
Sep	$24,000,000
Oct	$121,000,000
Nov	$107,600,000
Dec	$150,000,000
12 Month Averag	$71,550,000
PROJECTED FISCAL YEAR 2019	
2019 Jan *	$199,000,000
Feb *	$63,000,000
Mar *	$0
Apr *	$0
May *	$134,000,000
Jun *	$244,000,000
Jul *	$227,000,000
Aug	$201,549,512
Sep	$298,379,907
Oct	$299,112,128
Nov	$297,730,313
Dec	$250,769,165
12 Month Averag	$184,545,085

* Actuals

Month	Short Term Debt NSP-Minnesota 1/
PROPOSED TEST YEAR 2020	
2020 Jan	$235,460,046
Feb	$119,925,028
Mar	$81,667,031
Apr	$90,432,124
May	$202,011,399
Jun	$0
Jul	$0
Aug	$3,596,584
Sep	$90,283,655
Oct	$119,246,715
Nov	$130,184,358
Dec	$235,030,485
12 Month Averag	$108,986,452

1/ Month-end balances.
Includes commercial paper, utility money pool or direct borrowings under the credit facility.

Northern States Power Company (Minnesota)
Consolidated
RATE OF RETURN COST OF CAPITAL SCHEDULES
Cost of Short Term Debt

Twelve-month Average

		Interest Cost		Financing Charge		
	Average Net Proceeds 1/	Total 12 Month Interest Expense 2/	Average Interest Cost	Total 12 Month Financing Charge 2/	Average Interest Cost	Average Capital Cost
	(A)	(B)	(C) (B) / (A)	(D)	(E) (D) / (A)	(F) (C)+ (E)
MOST RECENT FISCAL YEAR 2018						
Short-term borrowings 3/	$ 51,086,820	$ 1,044,340	2.04%	$ 471,197	0.91%	2.97%
Direct Borrowings under 5-year credit facilit	$ -	$ -	0.00%	$ -	0.00%	0.00%
Weighted Cost	$ 51,086,820	$ 1,044,340	2.04%	$ 471,197	0.92%	$\boxed{2.97\%}$
PROJECTED FISCAL YEAR 2019						
Short-term borrowings 3/	$181,912,550	$4,449,409	2.45%	$484,024	0.27%	2.71%
Direct Borrowings under 5-year credit facilit	$ -	$ -	0.00%	$ -	0.00%	0.00%
Weighted Cost	$ 181,912,550	$ 4,449,409	2.45%	$ 484,024	0.27%	$\boxed{2.71\%}$
PROPOSED TEST YEAR 2020						
Short-term borrowings 3/	$109,642,230	$2,753,784	2.51%	$503,847	0.46%	2.97%
Direct Borrowings under 5-year credit facilit	$ -	$ -	0.00%	$ -	0.00%	0.00%
Weighted Cost	$ 109,642,230	$ 2,753,784	2.51%	$ 503,847	0.46%	$\boxed{2.97\%}$

1/ Actuals are 12 month average of average daily balances.
Forecast are 12 month average of current and prior month -end average.

2/ Includes interest expense on short term debt and finance charges associated with the June 2016 and June 2019 five year credit facility.
The finance charges represent the monthly cost of NSP-MN unused portion of the credit facility which is primarily used for commercial pape

3/ Based on simple average of net proceeds average balances.

4/ Direct Borrowings from the 5-year credit facility are shown as a separate line item.
Upfront fees related to the 5-year credit facility are included in the long-term debt cost and amortized over the life of the credit facility.

Twelve-month Average

Month	Short Term Debt NSP-Minnesota 1/
MOST RECENT FISCAL YEAR 2018	
2018 Jan	$189,000,000
Feb	$83,000,000
Mar	$0
Apr	$0
May	$0
Jun	$62,000,000
Jul	$99,000,000
Aug	$23,000,000
Sep	$24,000,000
Oct	$121,000,000
Nov	$107,600,000
Dec	$150,000,000
12 Month Average	$71,550,000
PROJECTED FISCAL YEAR 2019	
2019 Jan *	$199,000,000
Feb *	$63,000,000
Mar *	$0
Apr *	$0
May *	$134,000,000
Jun *	$244,000,000
Jul *	$227,000,000
Aug	$201,549,512
Sep	$298,379,907
Oct	$299,112,128
Nov	$297,730,313
Dec	$250,769,165
12 Month Average	$184,545,085

* Actuals

Month	Short Term Debt NSP-Minnesota 1/
PROPOSED TEST YEAR 2020	
2016 Jan	$235,460,046
Feb	$119,925,028
Mar	$81,667,031
Apr	$90,432,124
May	$202,011,399
Jun	$0
Jul	$0
Aug	$3,596,584
Sep	$90,283,655
Oct	$119,246,715
Nov	$130,184,358
Dec	$235,030,485
12 Month Average	$108,986,452

1/ Month-end balances.
Includes commercial paper, utility money pool or direct borrowings under the credit facility.

Twelve-month Average

Month	Short Term Debt NSP-Minnesota 1/
PROPOSED TEST YEAR 2020	
2016 Jan	$235,460,046
Feb	$119,925,028
Mar	$81,667,031
Apr	$90,432,124
May	$202,011,399
Jun	$0
Jul	$0
Aug	$3,596,584
Sep	$90,283,655
Oct	$119,246,715
Nov	$130,184,358
Dec	$235,030,485
12 Month Averag	$108,986,452

1/ Month-end balances.
Includes commercial paper, utility money pool or direct borrowings under the credit facility.

Xcel Energy Inc.
Consolidated
RATE OF RETURN COST OF CAPITAL SCHEDULES
Short Term Debt Balances
($000's)

Twelve-month Average

Month	Short Term Debt Xcel Consolidated 1/	Short Term Interest Exp & Fees Xcel Consolidated 2/	Short Term Debt Cost Xcel Consolidated
MOST RECENT FISCAL YEAR 2018			
2018 Jan	$1,158,000		
Feb	$1,058,000		
Mar	$1,025,000		
Apr	$955,000		
May	$1,227,000		
Jun	$682,000		
Jul	$669,000		
Aug	$705,000		
Sep	$437,000		
Oct	$607,000		
Nov	$527,000		
Dec	$1,038,000		
12 Month Average	$840,667	22,072	2.63%
PROJECTED FISCAL YEAR 2019			
2019 Jan	$1,390,425		
Feb	$1,327,000		
Mar	$1,252,000		
Apr	$1,281,000		
May	$1,413,000		
Jun	$1,597,000		
Jul	$1,732,000		
Aug	$1,126,886		
Sep	$1,271,029		
Oct	$1,382,581		
Nov	$1,084,403		
Dec	$1,215,419		
12 Month Average	$1,339,395	40,596	3.03%
PROJECTED FISCAL YEAR 2020			
2020 Jan	$1,533,628		
Feb	$1,489,926		
Mar	$1,068,957		
Apr	$1,230,398		
May	$1,471,422		
Jun	$1,200,486		
Jul	$1,192,573		
Aug	$1,103,487		
Sep	$941,994		
Oct	$1,085,957		
Nov	$736,011		
Dec	$1,030,174		
12 Month Average	$1,173,751	37,407	3.19%

1/ Includes Direct borrowings from 5-year credit facility which are considered short-term debt for regulatory purposes.
2/ Includes interest expense and facility fees.
Note-Credit Facility Re-syndicated June 2016 & June 2019.

TEST YEAR - 2020 FORECASTED SHORT TERM DEBT AND COST

		Cost of Short Term Debt			
	Month End Balances	Average Of Month End Balances (1)	Monthly Interest Expense (2)	Monthly Fees Expense (3)	Average Short Term Debt Cost
2020 Jan	$235,460,046	$243,114,605	$500,343	$42,655	
2020 Feb	$119,925,028	$177,692,537	$342,107	$39,984	
2020 Mar	$81,667,031	$100,796,029	$207,444	$42,655	
2020 Apr	$90,432,124	$86,049,578	$171,382	$41,319	
2020 May	$202,011,399	$146,221,762	$300,933	$42,655	
2020 June	$0	$101,005,700	$201,170	$41,319	
2020 Jul	$0	$0	$0	$42,655	
2020 Aug	$3,596,584	$1,798,292	$3,778	$42,655	
2020 Sep	$90,283,655	$46,940,120	$95,445	$41,319	
2020 Oct	$119,246,715	$104,765,185	$239,068	$42,655	
2020 Nov	$130,184,358	$124,715,537	$275,413	$41,319	
2020 Dec	$235,030,485	$182,607,421	$416,700	$42,655	
Average	$108,986,452	$109,642,230			
Total			$ 2,753,784	$ 503,847	
			2.51%	0.46%	2.97%

(1) January through December Average of Month End Balances.

(2) Monthly Interest Expense is based on the weighted average of short term debt outstanding and Interest Rates are based on the Global Insights Inc Forecast.

(3) Ongoing fees for NSP-MN's five-year credit facility that was re-syndicated on June 7, 2019. This expense represents the monthly cost of NSP-MN unused portion of the credit facility. Credit facility is used primarily as back up for commercial paper and letters of credit. (Upfront expenses for the five year credit facility are amortized over the life of the facility and are included in the cost of long term debt.)

PLAN YEAR - 2021 FORECASTED SHORT TERM DEBT AND COST

		Cost of Short Term Debt			
	Month End Balances	Average Of Month End Balances (1)	Monthly Interest Expense (2)	Monthly Fees Expense (3)	Average Short Term Debt Cost
2021 Jan	$268,108,276	$251,569,380	$576,234	$42,655	
2021 Feb	$200,463,215	$234,285,746	$484,711	$38,648	
2021 Mar	$147,580,500	$174,021,857	$398,607	$42,655	
2021 Apr	$183,674,019	$165,627,259	$367,140	$41,319	
2021 May	$0	$91,837,010	$210,358	$42,655	
2021 June	$125,927,695	$62,963,848	$139,570	$41,319	
2021 Jul	$214,016,604	$169,972,150	$389,331	$42,655	
2021 Aug	$148,687,015	$181,351,810	$415,396	$42,655	
2021 Sep	$93,934,275	$121,310,645	$268,905	$41,319	
2021 Oct	$202,722,003	$148,328,139	$339,754	$42,655	
2021 Nov	$224,031,409	$213,376,706	$472,985	$41,319	
2021 Dec	$174,778,307	$199,404,858	$456,748	$42,655	
Average	$165,326,943	$167,837,451			
Total			$ 4,519,739	$ 502,511	
			2.69%	0.30%	2.99%

(1) January through December Average of Month End Balances.

(2) Monthly Interest Expense based on weighted average of short term debt outstanding and Interest Rates based on Global Insights Inc Forecast.

(3) Ongoing fees for NSP-MN's five-year credit facility that was re-syndicated on June 7, 2019. This expense represents the monthly cost of NSP-MN unused portion of the credit facility. Credit facility is used primarily as back up for commercial paper and letters of credit. (Upfront expenses for the five year credit facility are amortized over the life of the facility and are included in the cost of long term debt.)

PLAN YEAR - 2022 FORECASTED SHORT TERM DEBT AND COST

		Cost of Short Term Debt			
	Month End Balances	Average Of Month End Balances (1)	Monthly Interest Expense (2)	Monthly Fees Expense (3)	Average Short Term Debt Cost
2022 Jan	$248,078,786	$211,428,546	$486,109	$42,655	
2022 Feb	$159,902,562	$203,990,674	$423,621	$38,648	
2022 Mar	$79,798,571	$119,850,566	$275,556	$42,655	
2022 Apr	$127,557,262	$103,677,917	$230,683	$41,319	
2022 May	$267,296,543	$197,426,903	$453,917	$42,655	
2022 June	$0	$133,648,272	$297,367	$41,319	
2022 Jul	$0	$0	$0	$42,655	
2022 Aug	$112,459,550	$56,229,775	$128,797	$42,655	
2022 Sep	$105,150,230	$108,804,890	$241,184	$41,319	
2022 Oct	$204,236,864	$154,693,547	$354,334	$42,655	
2022 Nov	$238,437,553	$221,337,208	$490,631	$41,319	
2022 Dec	$279,113,075	$258,775,314	$592,739	$42,655	
Average	$151,835,916	$147,488,634			
Total			$ 3,974,940	$ 502,511	
			2.70%	0.34%	3.04%

(1) January through December Average of Month End Balances.

(2) Monthly Interest Expense based on weighted average of short term debt outstanding and Interest Rates based on Global Insights Inc Forecast.

(3) Ongoing fees for NSP-MN's five-year credit facility that was re-syndicated on June 7, 2019. This expense represents the monthly cost of NSP-MN unused portion of the credit facility. Credit facility is used primarily as back up for commercial paper and letters of credit. (Upfront expenses for the five year credit facility are amortized over the life of the facility and are included in the cost of long term debt.)

(000s)

Month	GAAP Common Equity Outstanding	Non-Regulated Subsidiaries*	Regulated Common Equity
MOST RECENT FISCAL YEAR 2018			
2017 Dec	$5,475,570	$933	$5,474,637
2018 Jan	$5,537,632	$937	$5,536,695
Feb	$5,571,629	$926	$5,570,703
Mar	$5,522,848	$915	$5,521,933
Apr	$5,538,709	$905	$5,537,804
May	$5,562,958	$918	$5,562,040
Jun	$5,526,761	$906	$5,525,855
Jul	$5,599,565	$895	$5,598,670
Aug	$5,630,030	$885	$5,629,145
Sep	$5,533,123	$866	$5,532,257
Oct	$5,556,021	$855	$5,555,166
Nov	$5,594,901	$994	$5,593,907
Dec	$5,573,159	$982	$5,572,176
13 Month Average	$5,555,608	$917	$5,554,691
PROJECTED FISCAL YEAR 2019			
2018 Dec	$5,573,101	$982	$5,572,119
2019 Jan	$5,720,480	$979	$5,719,501
Feb	$5,793,359	$968	$5,792,391
Mar	$5,761,915	$957	$5,760,958
Apr	$5,779,852	$952	$5,778,900
May	$5,799,251	$952	$5,798,299
Jun	$5,767,553	$941	$5,766,612
Jul	$5,952,668	$930	$5,951,738
Aug	$6,032,038	$930	$6,031,108
Sep	$6,007,576	$930	$6,006,646
Oct	$6,216,329	$930	$6,215,399
Nov	$6,291,485	$930	$6,290,555
Dec	$6,346,384	$930	$6,345,454
13 Month Average	$5,926,307	$947	$5,925,360
PROPOSED TEST YEAR YEAR 2020			
2019 Dec	$6,346,384	$930	$6,345,454
2020 Jan	$6,459,526	$930	$6,458,596
Feb	$6,518,524	$930	$6,517,594
Mar	$6,473,121	$930	$6,472,191
Apr	$6,488,467	$930	$6,487,537
May	$6,510,895	$930	$6,509,965
Jun	$6,483,361	$930	$6,482,431
Jul	$6,573,992	$930	$6,573,062
Aug	$6,675,891	$930	$6,674,961
Sep	$6,629,755	$930	$6,628,825
Oct	$6,757,834	$930	$6,756,904
Nov	$6,891,853	$930	$6,890,923
Dec	$6,930,433	$930	$6,929,503
13 Month Average	$6,595,388	$930	$6,594,458

*** United Power and Land**

(000s)

Month	GAAP Common Equity Outstanding
MOST RECENT FISCAL YEAR 2018	
2017 Dec	$5,475,570
2018 Jan	$5,537,632
Feb	$5,571,629
Mar	$5,522,848
Apr	$5,538,709
May	$5,562,958
Jun	$5,526,761
Jul	$5,599,565
Aug	$5,630,030
Sep	$5,533,123
Oct	$5,556,021
Nov	$5,594,901
Dec	$5,573,159
13 Month Average	$5,555,608
PROJECTED FISCAL YEAR 2019	
2018 Dec	$5,573,101
2019 Jan	$5,720,480
Feb	$5,793,359
Mar	$5,761,915
Apr	$5,779,852
May	$5,799,251
Jun	$5,767,553
Jul	$5,952,668
Aug	$6,032,038
Sep	$6,007,576
Oct	$6,216,329
Nov	$6,291,485
Dec	$6,346,384
13 Month Average	$5,926,307
PROPOSED TEST YEAR YEAR 2020	
2019 Dec	$6,346,384
2020 Jan	$6,459,526
Feb	$6,518,524
Mar	$6,473,121
Apr	$6,488,467
May	$6,510,895
Jun	$6,483,361
Jul	$6,573,992
Aug	$6,675,891
Sep	$6,629,755
Oct	$6,757,834
Nov	$6,891,853
Dec	$6,930,433
13 Month Average	$6,595,388

($000's)

Month	Common Equity Outstanding
MOST RECENT FISCAL YEAR 2018	
2017 Dec	11,454,835
2018 Jan	11,579,399
Feb	11,473,563
Mar	11,560,445
Apr	11,617,191
May	11,494,881
Jun	11,650,623
Jul	11,861,373
Aug	11,849,099
Sep	12,164,584
Oct	12,265,028
Nov	12,314,313
Dec	12,220,589
13 Month Average	$11,808,148
PROJECTED FISCAL YEAR 2019	
2018 Dec	12,220,589
2019 Jan	12,349,987
Feb	12,226,106
Mar	12,329,063
Apr	12,399,138
May	12,236,278
Jun	12,366,210
Jul	12,579,190
Aug	13,023,025
Sep	13,171,555
Oct	13,253,225
Nov	13,343,229
Dec	13,276,341
13 Month Average	$12,674,918
PROJECTED FISCAL YEAR 2020	
2019 Dec	13,276,341
2020 Jan	13,426,659
Feb	13,240,540
Mar	13,342,837
Apr	13,403,848
May	13,243,024
Jun	13,411,095
Jul	13,637,974
Aug	13,620,265
Sep	13,769,299
Oct	13,861,032
Nov	13,959,598
Dec	13,903,384
13 Month Average	$13,545,838

($000's)

TEST YEAR - 2020 FORECASTED EQUITY BALANCES

Month	GAAP Common Equity Outstanding	Non-Regulated Subsidiaries (1)	Regulated Common Equity
2019 Dec	$6,346,384	$930	$6,345,454
2020 Jan	$6,459,526	$930	$6,458,596
2020 Feb	$6,518,524	$930	$6,517,594
2020 Mar	$6,473,121	$930	$6,472,191
2020 Apr	$6,488,467	$930	$6,487,537
2020 May	$6,510,895	$930	$6,509,965
2020 Jun	$6,483,361	$930	$6,482,431
2020 Jul	$6,573,992	$930	$6,573,062
2020 Aug	$6,675,891	$930	$6,674,961
2020 Sep	$6,629,755	$930	$6,628,825
2020 Oct	$6,757,834	$930	$6,756,904
2020 Nov	$6,891,853	$930	$6,890,923
2020 Dec	$6,930,433	$930	$6,929,503
13 Month Average	$6,595,388	$930	$6,594,458

(1) United Power and Land.

($000's)

PLAN YEAR - 2021 FORECASTED EQUITY BALANCES

Month	GAAP Common Equity Outstanding	Non-Regulated Subsidiaries (1)	Regulated Common Equity
2020 Dec	$6,930,433	$930	$6,929,503
2021 Jan	$7,023,122	$930	$7,022,192
2021 Feb	$7,061,338	$930	$7,060,408
2021 Mar	$7,003,254	$930	$7,002,324
2021 Apr	$7,040,648	$930	$7,039,718
2021 May	$7,068,999	$930	$7,068,069
2021 June	$7,028,324	$930	$7,027,394
2021 Jul	$7,127,329	$930	$7,126,399
2021 Aug	$7,215,647	$930	$7,214,717
2021 Sep	$7,193,284	$930	$7,192,354
2021 Oct	$7,229,299	$930	$7,228,369
2021 Nov	$7,265,286	$930	$7,264,356
2021 Dec	$7,252,494	$930	$7,251,564
13 Month Average	$7,110,727	$930	$7,109,797

(1) United Power and Land.

($000's)

PLAN YEAR - 2022 FORECASTED EQUITY BALANCES

Month	GAAP Common Equity Outstanding	Non-Regulated Subsidiaries (1)	Regulated Common Equity
2021 Dec	$7,252,494	$930	$7,251,564
2022 Jan	$7,324,051	$930	$7,323,121
2022 Feb	$7,365,868	$930	$7,364,938
2022 Mar	$7,298,450	$930	$7,297,520
2022 Apr	$7,324,665	$930	$7,323,735
2022 May	$7,355,659	$930	$7,354,729
2022 June	$7,327,897	$930	$7,326,967
2022 Jul	$7,429,500	$930	$7,428,570
2022 Aug	$7,518,262	$930	$7,517,332
2022 Sep	$7,459,862	$930	$7,458,932
2022 Oct	$7,527,801	$930	$7,526,871
2022 Nov	$7,563,519	$930	$7,562,589
2022 Dec	$7,588,734	$930	$7,587,804
13 Month Average	$7,410,520	$930	$7,409,590

(1) United Power and Land.

Xcel Energy Inc.
Consolidated
RATE OF RETURN COST OF CAPITAL SCHEDULES
Preferred Equity
($000's)

Month	Preferred Equity Outstanding	Preferred Equity Dividend	Preferred Equity Redemption Premium	Preferred Equity Outstanding
MOST RECENT FISCAL YEAR 2018				
2017 Dec	0			
2018 Jan	0			
Feb	0			
Mar	0			
Apr	0			
May	0			
Jun	0			
Jul	0			
Aug	0			
Sep	0			
Oct	0			
Nov	0			
Dec	0			
13 Month Average	$0	$0	$0	N/A
PROJECTED FISCAL YEAR 2019				
2018 Dec	0			
2019 Jan	0			
Feb	0			
Mar	0			
Apr	0			
May	0			
Jun	0			
Jul	0			
Aug	0			
Sep	0			
Oct	0			
Nov	0			
Dec	0			
13 Month Average	$0	$0	$0	N/A
PROJECTED FISCAL YEAR 2020				
2019 Dec	0			
2020 Jan	0			
Feb	0			
Mar	0			
Apr	0			
May	0			
Jun	0			
Jul	0			
Aug	0			
Sep	0			
Oct	0			
Nov	0			
Dec	0			
13 Month Average	$0	$0	$0	N/A

Northern States Power Company
Electric Utility - Minnesota
Test Year Ending December 31, 2020
SALES AND REVENUE BY RATE SCHEDULE

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Exhibit No. ______(SVH-1)
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					Revenues ($1,000's)							
Service Schedule	**Average**	**MWH Sales**			**Summer**		**Winter**		**Annual**		**Increase**	
	Customers	Summer	Winter	Annual	Present	Ordered	Present	Ordered	Present	Ordered	Amount	Percent
Residential												
Residential	1,164,971	3,183,290	5,160,619	8,343,908	459,561	500,899	696,798	743,111	1,156,359	1,244,010	87,650	7.58%
Residential TOD	674	2,341	5,135	7,476	340	360	608	642	948	1,001	54	5.65%
Residential EV	952	17,200	38,107	55,308	1,549	1,607	3,182	3,305	4,731	4,911	181	3.82%
Load Management	3,589	9,134	35,029	44,164	870	898	2,877	2,954	3,747	3,852	105	2.81%
Res Total	**1,170,186**	**3,211,966**	**5,238,890**	**8,450,856**	**462,320**	**503,764**	**703,465**	**750,011**	**1,165,785**	**1,253,775**	**87,990**	**7.55%**
C&I - Non-Demand												
Small General	75,036	254,055	505,788	759,843	35,485	38,213	62,520	67,440	98,005	105,653	7,648	7.80%
Small General TOD	11,052	25,114	57,501	82,616	3,350	3,597	6,689	7,192	10,039	10,789	750	7.47%
Load Management	199	635	3,036	3,671	71	76	267	281	339	357	18	5.31%
C&I N-D Total	**86,287**	**279,804**	**566,326**	**846,130**	**38,906**	**41,885**	**69,476**	**74,913**	**108,383**	**116,798**	**8,416**	**7.76%**
C&I - Demand												
General	41,660	2,785,653	5,033,970	7,819,623	317,407	334,721	506,402	534,194	823,809	868,916	45,107	5.48%
General TOD	4,755	2,786,356	4,711,573	7,497,929	254,909	268,985	385,921	407,415	640,831	676,401	35,570	5.55%
Light Rail	16	7,099	17,062	24,161	709	753	1,535	1,632	2,244	2,386	142	6.32%
Peak-Controlled	1,412	377,377	719,986	1,097,363	40,910	43,190	71,576	75,623	112,486	118,814	6,327	5.62%
Peak-Controlled TOD	342	886,985	1,587,661	2,474,646	73,950	78,272	125,816	133,206	199,766	211,478	11,712	5.86%
Energy-Controlled	11	146,691	268,961	415,652	10,591	11,191	19,554	20,659	30,146	31,850	1,704	5.65%
Real Time Pricing	3	7,587	13,794	21,380	729	787	1,139	1,247	1,868	2,034.1	166	8.87%
C&I Dmd Total	**48,200**	**6,997,747**	**12,353,007**	**19,350,754**	**699,206**	**737,901**	**1,111,943**	**1,173,977**	**1,811,150**	**1,911,878**	**100,728**	**5.56%**
C&I Total	**134,486**	**7,277,551**	**12,919,332**	**20,196,884**	**738,113**	**779,786**	**1,181,420**	**1,248,890**	**1,919,532**	**2,028,676**	**109,144**	**5.69%**
Public Authorities												
Small Mun Pumping	930	2,239	4,883	7,123	331	356	621	671	952	1,028	76	7.93%
Municipal Pumping	574	24,950	35,861	60,810	3,206	3,375	4,186	4,409	7,392	7,784	392	5.31%
Siren Service	0	0	0	0	12	12	23	25	35	37	2	6.58%
PA Total	**1,504**	**27,189**	**40,744**	**67,933**	**3,548**	**3,743**	**4,831**	**5,105**	**8,379**	**8,849**	**470**	**5.61%**
Lighting												
System Service	0	7,275	24,758	32,034	5,872	6,747	11,997	13,730	17,869	20,477	2,608	14.59%
Energy	0	5,849	19,904	25,754	593	626	1,388	1,442	1,981	2,068	87	4.37%
Metered Energy	2,249	7,972	27,129	35,101	603	607	1,990	1,996	2,594	2,603	9	0.36%
Protective Lighting	0	7,698	22,088	29,786	1,367	1,460	2,899	3,076	4,266	4,536	270	6.33%
Lighting Total	**2,249**	**28,795**	**93,880**	**122,675**	**8,435**	**9,440**	**18,274**	**20,243**	**26,709**	**29,683**	**2,974**	**11.13%**
Total Retail	**1,308,426**	**10,545,500**	**18,292,846**	**28,838,347**	**1,212,415**	**1,296,733**	**1,907,989**	**2,024,250**	**3,120,405**	**3,320,983**	**200,578**	**6.43%**
Other Rev Increase					0	271	0	542	0	812.751	813	
Interdept. Increase					0	18	0	18	0	36	36	
Total Revenue	**1,308,426**	**10,545,500**	**18,292,846**	**28,838,347**	**1,212,415**	**1,297,022**	**1,907,989**	**2,024,810**	**3,120,405**	**3,321,832**	**201,427**	**6.46%**
Interdept Present	5	3,295	3,813	7,108	349	349	385	385	735	735	0	
Retail + ID	**1,308,431**	**10,548,796**	**18,296,660**	**28,845,455**	**1,212,765**	**1,297,371**	**1,908,375**	**2,025,195**	**3,121,140**	**3,322,567**	**201,427**	**6.45%**

Northern States Power Company
Electric Utility - Minnesota
Paln Year Ending December 31, 2021
SALES AND REVENUE BY RATE SCHEDULE

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Service Schedule	Average	MWH Sales			Revenues ($1,000's) Summer		Winter		Annual		Increase	
	Customers	Summer	Winter	Annual	Present	Ordered	Present	Ordered	Present	Ordered	Amount	Percent
Residential												
Residential	1,174,532	3,135,318	5,031,928	8,167,246	454,276	520,953	682,933	766,307	1,137,209	1,287,259	150,051	13.19%
Residential TOD	681	2,307	5,022	7,329	336	373	597	663	933	1,036	103	11.00%
Residential EV	1,333	25,717	45,910	71,627	2,319	2,518	3,852	4,197	6,171	6,716	545	8.83%
Load Management	3,650	9,034	34,588	43,622	865	947	2,851	3,126	3,716	4,073	357	9.61%
Res Total	**1,180,196**	**3,172,375**	**5,117,448**	**8,289,824**	**457,796**	**524,791**	**690,233**	**774,293**	**1,148,029**	**1,299,084**	**151,056**	**13.16%**
C&I - Non-Demand												
Small General	75,392	250,615	498,995	749,610	35,118	39,591	61,894	69,992	97,011	109,583	12,572	12.96%
Small General TOD	11,104	24,775	56,747	81,522	3,319	3,716	6,628	7,450	9,947	11,165	1,218	12.24%
Load Management	199	626	2,995	3,622	70	78	265	292	335	370	35	10.46%
C&I N-D Total	**86,695**	**276,016**	**558,737**	**834,754**	**38,507**	**43,385**	**68,786**	**77,734**	**107,294**	**121,118**	**13,824**	**12.88%**
C&I - Demand												
General	41,857	2,747,863	4,967,099	7,714,961	313,694	343,278	500,863	550,554	814,556	893,832	79,275	9.73%
General TOD	4,775	2,743,333	4,643,641	7,386,974	251,627	275,454	381,469	419,293	633,095	694,747	61,652	9.74%
Light Rail	16	7,003	16,815	23,818	701	773	1,516	1,680	2,217	2,454	236	10.66%
Peak-Controlled	1,419	372,269	710,417	1,082,686	40,444	44,525	70,784	78,146	111,229	122,671	11,442	10.29%
Peak-Controlled TOD	343	873,782	1,562,302	2,436,084	73,042	80,580	124,152	137,229	197,194	217,809	20,615	10.45%
Energy-Controlled	11	144,481	264,604	409,086	10,460	11,587	19,288	21,371	29,749	32,958	3,209	10.79%
Real Time Pricing	3	7,472	13,562	21,034	719	807	1,123	1,282	1,843	2,088.3	245	13.32%
C&I Dmd Total	**48,425**	**6,896,203**	**12,178,439**	**19,074,642**	**690,688**	**757,004**	**1,099,195**	**1,209,555**	**1,789,883**	**1,966,558**	**176,675**	**9.87%**
C&I Total	**135,120**	**7,172,219**	**12,737,176**	**19,909,395**	**729,195**	**800,388**	**1,167,981**	**1,287,288**	**1,897,177**	**2,087,677**	**190,500**	**10.04%**
Public Authorities												
Small Mun Pumping	932	2,241	4,819	7,060	332	373	615	696	947	1,069	122	12.89%
Municipal Pumping	574	24,984	35,384	60,368	3,215	3,508	4,138	4,543	7,353	8,051	698	9.49%
Siren Service	0	0	0	0	12	13	23	25	35	38	3	9.21%
PA Total	**1,506**	**27,226**	**40,202**	**67,428**	**3,558**	**3,894**	**4,777**	**5,264**	**8,335**	**9,158**	**823**	**9.87%**
Lighting												
System Service	0	7,281	24,752	32,034	5,874	7,046	12,001	14,332	17,875	21,378	3,503	19.60%
Energy	0	5,854	19,900	25,754	594	648	1,392	1,487	1,986	2,135	149	7.51%
Metered Energy	2,249	7,809	26,545	34,354	593	615	1,954	2,023	2,547	2,639	91	3.57%
Protective Lighting	0	7,591	21,738	29,329	1,366	1,542	2,894	3,237	4,260	4,779	519	12.18%
Lighting Total	**2,249**	**28,534**	**92,936**	**121,470**	**8,427**	**9,851**	**18,241**	**21,079**	**26,668**	**30,930**	**4,262**	**15.98%**
Total Retail	**1,319,070**	**10,400,355**	**17,987,762**	**28,388,117**	**1,198,976**	**1,338,924**	**1,881,232**	**2,087,924**	**3,080,208**	**3,426,848**	**346,640**	**11.25%**
Other Rev Increase					0	362	0	725	0	1,087	1,087	
Interdept. Increase					0	33	0	34	0	67	67	
Total Revenue	**1,319,070**	**10,400,355**	**17,987,762**	**28,388,117**	**1,198,976**	**1,339,320**	**1,881,232**	**2,088,683**	**3,080,208**	**3,428,003**	**347,795**	**11.29%**
Interdept Present	5	3,295	3,813	7,108	350	350	386	386	736	736	0	
Retail + ID	**1,319,075**	**10,403,650**	**17,991,575**	**28,395,225**	**1,199,326**	**1,339,670**	**1,881,618**	**2,089,069**	**3,080,944**	**3,428,739**	**347,795**	**11.29%**

Northern States Power Company
Electric Utility - Minnesota
Paln Year Ending December 31, 2022
SALES AND REVENUE BY RATE SCHEDULE

Docket No. E002/GR-19-564
Exhibit No. ______(SVH-1)
Schedule 4
Page 1 of 1

Service Schedule	Average Customers	MWH Sales			Revenues ($1,000's) Summer		Winter		Annual		Increase	
		Summer	Winter	Annual	Present	Ordered	Present	Ordered	Present	Ordered	Amount	Percent
Residential												
Residential	1,183,337	3,130,356	5,016,829	8,147,185	453,756	541,458	681,357	795,621	1,135,113	1,337,079	201,966	17.79%
Residential TOD	686	2,305	5,017	7,322	336	387	597	690	933	1,077	144	15.47%
Residential EV	1,714	31,435	63,999	95,434	2,835	3,205	5,357	6,092	8,192	9,297	1,105	13.48%
Load Management	3,711	9,065	34,782	43,847	868	993	2,866	3,296	3,734	4,289	555	14.85%
Res Total	**1,189,448**	**3,173,161**	**5,120,628**	**8,293,789**	**457,795**	**546,044**	**690,178**	**805,699**	**1,147,973**	**1,351,742**	**203,769**	**17.75%**
C&I - Non-Demand												
Small General	75,741	247,369	495,622	742,991	34,698	40,440	61,518	71,981	96,215	112,421	16,206	16.84%
Small General TOD	11,156	24,456	56,362	80,818	3,283	3,794	6,590	7,660	9,873	11,454	1,581	16.02%
Load Management	200	618	2,978	3,596	70	80	263	304	333	384	51	15.34%
C&I N-D Total	**87,098**	**272,443**	**554,962**	**827,405**	**38,050**	**44,314**	**68,370**	**79,945**	**106,421**	**124,259**	**17,838**	**16.76%**
C&I - Demand												
General	42,050	2,712,335	4,932,438	7,644,773	309,522	349,110	497,222	563,509	806,744	912,619	105,875	13.12%
General TOD	4,795	2,743,042	4,669,090	7,412,132	251,757	283,933	383,373	434,361	635,129	718,294	83,165	13.09%
Light Rail	16	6,913	16,701	23,614	692	788	1,505	1,722	2,197	2,510	313	14.23%
Peak-Controlled	1,426	367,467	705,404	1,072,871	39,911	45,395	70,252	80,152	110,163	125,547	15,384	13.96%
Peak-Controlled TOD	344	862,905	1,550,110	2,413,015	72,111	82,180	123,143	140,644	195,254	222,824	27,570	14.12%
Energy-Controlled	11	142,704	262,506	405,210	9,047	10,538	18,898	21,666	27,945	32,203	4,259	15.24%
Real Time Pricing	3	7,381	13,456	20,837	710	822	1,114	1,312	1,825	2,133.5	309	16.92%
C&I Dmd Total	**48,645**	**6,842,747**	**12,149,704**	**18,992,452**	**683,750**	**772,765**	**1,095,507**	**1,243,366**	**1,779,257**	**2,016,131**	**236,875**	**13.31%**
C&I Total	**135,742**	**7,115,190**	**12,704,666**	**19,819,856**	**721,800**	**817,079**	**1,163,877**	**1,323,311**	**1,885,677**	**2,140,390**	**254,713**	**13.51%**
Public Authorities												
Small Mun Pumping	931	2,239	4,813	7,053	331	385	614	718	946	1,103	157	16.63%
Municipal Pumping	575	24,981	35,379	60,360	3,213	3,611	4,135	4,677	7,347	8,287	940	12.79%
Siren Service	0	0	0	0	12	13	23	25	35	38	3	9.21%
PA Total	**1,506**	**27,221**	**40,192**	**67,413**	**3,555**	**4,008**	**4,772**	**5,420**	**8,328**	**9,428**	**1,100**	**13.21%**
Lighting												
System Service	0	7,312	24,722	32,034	5,875	7,225	12,001	14,688	17,875	21,913	4,037	22.59%
Energy	0	5,878	19,875	25,754	595	664	1,392	1,521	1,986	2,185	199	10.00%
Metered Energy	2,249	8,032	27,156	35,187	609	647	1,998	2,120	2,607	2,768	161	6.17%
Protective Lighting	0	7,511	21,610	29,121	1,364	1,608	2,892	3,373	4,255	4,981	725	17.05%
Lighting Total	**2,249**	**28,732**	**93,363**	**122,095**	**8,442**	**10,144**	**18,282**	**21,702**	**26,724**	**31,846**	**5,122**	**19.17%**
Total Retail	**1,328,945**	**10,344,304**	**17,958,849**	**28,303,153**	**1,191,593**	**1,377,275**	**1,877,109**	**2,156,132**	**3,068,702**	**3,533,407**	**464,705**	**15.14%**
Other Rev Increase					0	436	0	872	0	1,308	1,308	
Interdept. Increase					0	45	0	47	0	91	91	
Total Revenue	**1,328,945**	**10,344,304**	**17,958,849**	**28,303,153**	**1,191,593**	**1,377,756**	**1,877,109**	**2,157,051**	**3,068,702**	**3,534,807**	**466,105**	**15.19%**
Interdept Present	5	3,295	3,813	7,108	350	350	386	386	736	736	0	
Retail + ID	**1,328,950**	**10,347,599**	**17,962,662**	**28,310,262**	**1,191,943**	**1,378,106**	**1,877,495**	**2,157,437**	**3,069,438**	**3,535,542**	**466,105**	**15.19%**

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
		Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A01 Res OH ResReg Secondary																
Cust Chg	Bills	2,973,058	5,949,267	8,922,325	$8.55	$8.55	$10.09	$10.09	25,432	50,891	76,323	29,990	60,011	90,000	13,678	17.9%
Energy	MWH	1,742,970	2,773,802	4,516,773	$103.01	$88.03	$115.77	$99.85	179,543	244,178	423,721	201,784	276,964	478,748	55,027	13.0%
SvrSwtchAC	MWH	602,597	0	602,597	-$20.04	$0.00	-$10.00	$0.00	-12,078	0	-12,078	-7,495	0	-7,495	4,583	-37.9%
SvrSwtchWH	MWH	12,881	23,708	36,589	-$2.67	-$2.29	-$2.00	-$2.00	-34	-54	-89	-27	-50	-78	11	-12.6%
LowIncCredit	MWH	141,982	283,964	425,947	-$15.00	-$15.00	-$15.00	-$15.00	-2,130	-4,259	-6,389	-2,130	-4,259	-6,389	0	0.0%
Fuel Cost	MWH	1,742,970	2,773,802	4,516,773	$30.62	$26.65	$30.38	$26.45	53,363	73,930	127,293	52,950	73,358	126,308	-986	-0.8%
Riders	MWH	1,742,970	2,773,802	4,516,773	$6.39	$6.39	$1.19	$1.19	11,143	17,734	28,878	2,076	3,304	5,380	-23,497	-81.4%
Total:									255,240	382,419	637,658	277,148	409,327	686,475	48,816	7.7%
A01 Res OH ResSH Secondary																
Cust Chg	Bills	101,459	202,369	303,828	$10.55	$10.55	$12.09	$12.09	1,071	2,136	3,207	1,226	2,446	3,672	466	14.5%
Energy	MWH	54,130	188,691	242,820	$103.01	$59.88	$115.77	$67.89	5,576	11,299	16,875	6,267	12,810	19,077	2,202	13.0%
SvrSwtchAC	MWH	8,677	0	8,677	-$20.04	$0.00	-$10.00	$0.00	-174	0	-174	-90	0	-90	84	-48.4%
SvrSwtchWH	MWH	1,266	3,845	5,111	-$2.67	-$1.73	-$2.00	-$2.00	-3	-7	-10	-3	-8	-11	-1	8.0%
LowIncCredit	MWH	4,835	9,670	14,505	-$15.00	-$15.00	-$15.00	-$15.00	-73	-145	-218	-73	-145	-218	0	0.0%
Fuel Cost	MWH	54,130	188,691	242,820	$30.62	$26.65	$30.38	$26.45	1,657	5,029	6,686	1,644	4,990	6,635	-52	-0.8%
Riders	MWH	54,130	188,691	242,820	$6.39	$6.39	$1.19	$1.19	346	1,206	1,552	64	225	289	-1,263	-81.4%
Total:									8,400	19,518	27,919	9,037	20,318	29,355	1,436	5.1%
A03 Res UG ResReg Secondary																
Cust Chg	Bills	1,548,344	3,098,325	4,646,669	$10.55	$10.55	$12.09	$12.09	16,341	32,700	49,042	18,715	37,450	56,165	7,123	14.5%
Energy	MWH	1,359,996	2,106,816	3,466,812	$103.01	$88.03	$115.77	$99.85	140,093	185,463	325,556	157,447	210,366	367,812	42,256	13.0%
SvrSwtchAC	MWH	679,460	0	679,460	-$20.04	$0.00	-$10.00	$0.00	-13,619	0	-13,619	-7,500	0	-7,500	6,120	-44.9%
SvrSwtchWH	MWH	6,246	11,209	17,455	-$2.67	-$2.29	-$2.00	-$2.00	-17	-26	-42	-13	-24	-37	5	-12.7%
LowIncCredit	MWH	73,943	147,886	221,829	-$15.00	-$15.00	-$15.00	-$15.00	-1,109	-2,218	-3,327	-1,109	-2,218	-3,327	0	0.0%
Fuel Cost	MWH	1,359,996	2,106,816	3,466,812	$30.62	$26.65	$30.38	$26.45	41,638	56,153	97,791	41,316	55,718	97,034	-757	-0.8%
Riders	MWH	1,359,996	2,106,816	3,466,812	$6.39	$6.39	$1.19	$1.19	8,695	13,470	22,165	1,620	2,510	4,130	-18,035	-81.4%
Total:									192,023	285,542	477,564	210,475	303,801	514,277	36,712	7.7%
A03 Res UG ResSH Secondary																
Cust Chg	Bills	35,504	70,811	106,315	$12.55	$12.55	$14.09	$14.09	446	889	1,335	500	998	1,498	163	12.2%
Energy	MWH	26,167	91,216	117,384	$103.01	$59.88	$115.77	$67.89	2,695	5,462	8,158	3,029	6,193	9,222	1,065	13.0%
SvrSwtchAC	MWH	9,311	0	9,311	-$20.04	$0.00	-$10.00	$0.00	-187	0	-187	-92	0	-92	94	-50.5%
SvrSwtchWH	MWH	1,078	3,721	4,798	-$2.67	-$1.73	-$2.00	-$2.00	-3	-6	-9	-2	-8	-10	-1	9.2%
LowIncCredit	MWH	1,692	3,384	5,075	-$15.00	-$15.00	-$15.00	-$15.00	-25	-51	-76	-25	-51	-76	0	0.0%
Fuel Cost	MWH	26,167	91,216	117,384	$30.62	$26.65	$30.38	$26.45	801	2,431	3,232	795	2,412	3,207	-25	-0.8%
Riders	MWH	26,167	91,216	117,384	$6.39	$6.39	$1.19	$1.19	167	583	750	31	109	140	-611	-81.4%
Total:									3,895	9,308	13,203	4,236	9,653	13,888	685	5.2%
A00 WtrHeating ResSH Secondary																
Cust Chg	Bills	172	341	513	$0.00	$0.00	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Energy	MWH	27	93	120	$103.01	$88.03	$115.77	$99.85	3	8	11	3	9	12	1	13.2%
Fuel Cost	MWH	27	93	120	$30.62	$26.65	$30.38	$26.45	1	2	3	1	2	3	0	-0.8%
Riders	MWH	27	93	120	$6.39	$6.39	$1.19	$1.19	0	1	1	0	0	0	-1	-81.4%
Total:									4	11	15	4	12	16	1	5.3%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A02 Res TOD OH ResReg Secondary																	
Cust Chg		Bills	1,226	2,453	3,679	$10.55	$10.55	$12.09	$12.09	13	26	39	15	30	44	6	14.5%
Energy	On	MWH	296	557	854	$204.97	$165.08	$226.18	$183.71	61	92	153	67	102	169	17	10.9%
Energy	Off	MWH	628	1,384	2,012	$41.70	$41.70	$49.58	$49.58	26	58	84	31	69	100	16	18.9%
Fuel Cost		MWH	924	1,942	2,865	$30.62	$26.65	$30.38	$26.45	28	52	80	28	51	79	-1	-0.8%
Riders		MWH	924	1,942	2,865	$6.39	$6.39	$1.19	$1.19	6	12	18	1	2	3	-15	-81.4%
Total:										134	240	374	142	254	396	23	6.1%
A02 Res TOD OH ResSH Secondary																	
Cust Chg		Bills	164	324	488	$12.55	$12.55	$14.09	$14.09	2	4	6	2	5	7	1	12.2%
Energy	On	MWH	54	187	240	$204.97	$92.84	$226.18	$101.05	11	17	28	12	19	31	3	9.4%
Energy	Off	MWH	117	407	523	$41.70	$41.70	$49.58	$49.58	5	17	22	6	20	26	4	18.9%
Fuel Cost		MWH	170	593	764	$30.62	$26.65	$30.38	$26.45	5	16	21	5	16	21	0	-0.8%
Riders		MWH	170	593	764	$6.39	$6.39	$1.19	$1.19	1	4	5	0	1	1	-4	-81.4%
Total:										24	58	82	26	60	86	3	4.1%
A08 Res EV ResReg Secondary																	
Cust Chg		Bills	3,195	6,081	9,276	$4.95	$4.95	$5.50	$5.50	16	30	46	18	33	51	5	11.1%
Energy	On	MWH	972	2,160	3,132	$204.97	$165.08	$226.18	$183.71	199	357	556	220	397	617	61	10.9%
Energy	Off	MWH	12,317	27,302	39,619	$41.70	$41.70	$49.58	$49.58	514	1,138	1,652	611	1,354	1,964	312	18.9%
Fuel Cost		MWH	13,289	29,462	42,751	$30.62	$26.65	$30.38	$26.45	407	785	1,192	404	779	1,183	-9	-0.8%
Riders		MWH	13,289	29,462	42,751	$6.39	$6.39	$1.19	$1.19	85	188	273	16	35	51	-222	-81.4%
Total:										1,221	2,499	3,719	1,268	2,598	3,866	147	3.9%
A80 Res EV Pilot Bund ResReg Secondary																	
Cust Chg		Bills	504	960	1,464	$17.47	$17.47	$18.00	$18.00	9	17	26	9	17	26	1	3.0%
Energy	On	MWH	56	124	181	$204.97	$165.08	$226.18	$183.71	12	21	32	13	23	36	4	10.9%
Energy	Off	MWH	2,916	6,446	9,362	$41.70	$41.70	$49.58	$49.58	122	269	390	145	320	464	74	18.9%
Fuel Cost		MWH	2,973	6,570	9,543	$30.62	$26.65	$30.38	$26.45	91	175	266	90	174	264	-2	-0.8%
Riders		MWH	2,973	6,570	9,543	$6.39	$6.39	$1.19	$1.19	19	42	61	4	8	11	-50	-81.4%
Total:										252	523	775	260	541	801	26	3.4%
A81 Res EV Pilot PrePay ResReg Secondary																	
Cust Chg		Bills	236	448	684	$7.10	$7.10	$7.50	$7.50	2	3	5	2	3	5	0	5.6%
Energy	On	MWH	5	11	16	$204.97	$165.08	$226.18	$183.71	1	2	3	1	2	3	0	10.9%
Energy	Off	MWH	934	2,064	2,998	$41.70	$41.70	$49.58	$49.58	39	86	125	46	102	149	24	18.9%
Fuel Cost		MWH	939	2,075	3,014	$30.62	$26.65	$30.38	$26.45	29	55	84	29	55	83	-1	-0.8%
Riders		MWH	939	2,075	3,014	$6.39	$6.39	$1.19	$1.19	6	13	19	1	2	4	-16	-81.4%
Total:										76	160	236	79	165	244	8	3.3%
A04 Res TOD UG ResReg Secondary																	
Cust Chg		Bills	1,149	2,300	3,449	$12.55	$12.55	$14.09	$14.09	14	29	43	16	32	49	5	12.2%
Energy	On	MWH	363	606	970	$204.97	$165.08	$226.18	$183.71	74	100	175	82	111	194	19	10.9%
Energy	Off	MWH	732	1,463	2,194	$41.70	$41.70	$49.58	$49.58	31	61	92	36	73	109	17	18.9%
Fuel Cost		MWH	1,095	2,069	3,164	$30.62	$26.65	$30.38	$26.45	34	55	89	33	55	88	-1	-0.8%
Riders		MWH	1,095	2,069	3,164	$6.39	$6.39	$1.19	$1.19	7	13	20	1	2	4	-16	-81.4%
Total:										160	258	418	169	274	443	24	5.8%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A04 Res TOD UG ResSH Secondary																	
Cust Chg		Bills	160	315	475	$14.55	$14.55	$16.09	$16.09	2	5	7	3	5	8	1	10.5%
Energy	On	MWH	44	154	198	$204.97	$92.84	$226.18	$101.05	9	14	23	10	16	26	2	9.4%
Energy	Off	MWH	108	377	485	$41.70	$41.70	$49.58	$49.58	5	16	20	5	19	24	4	18.9%
Fuel Cost		MWH	152	531	683	$30.62	$26.65	$30.38	$26.45	5	14	19	5	14	19	0	-0.8%
Riders		MWH	152	531	683	$6.39	$6.39	$1.19	$1.19	1	3	4	0	1	1	-4	-81.4%
Total:										22	52	74	23	54	77	3	4.1%
A05 EnergyCtrl N/D ResReg Secondary																	
Cust Chg		Bills	2,441	4,883	7,324	$4.95	$4.95	$5.50	$5.50	12	24	36	13	27	40	4	11.1%
Energy		MWH	1,100	5,351	6,451	$44.87	$44.87	$51.91	$51.91	49	240	289	57	278	335	45	15.7%
Opt Energy		MWH	25	109	134	$103.01	$44.87	$115.77	$51.91	3	5	7	3	6	9	1	14.6%
Fuel Cost		MWH	1,125	5,461	6,585	$30.62	$26.65	$30.38	$26.45	34	146	180	34	144	179	-1	-0.8%
Riders		MWH	1,125	5,461	6,585	$6.39	$6.39	$1.19	$1.19	7	35	42	1	7	8	-34	-81.4%
Total:										106	450	555	109	461	570	15	2.7%
A05 EnergyCtrl N/D ResSH Secondary																	
Cust Chg		Bills	10,433	20,808	31,241	$4.95	$4.95	$5.50	$5.50	52	103	155	57	114	172	17	11.1%
Energy		MWH	6,988	23,846	30,834	$44.87	$44.87	$51.91	$51.91	314	1,070	1,384	363	1,238	1,601	217	15.7%
Opt Energy		MWH	768	3,190	3,958	$103.01	$44.87	$115.77	$51.91	79	143	222	89	166	255	32	14.5%
Fuel Cost		MWH	7,756	27,036	34,792	$30.62	$26.65	$30.38	$26.45	237	721	958	236	715	951	-7	-0.8%
Riders		MWH	7,756	27,036	34,792	$6.39	$6.39	$1.19	$1.19	50	173	222	9	32	41	-181	-81.4%
Total:										731	2,210	2,941	754	2,265	3,019	78	2.7%
A05 EnergyCtrl N/D Sm C&I Secondary																	
Cust Chg		Bills	448	896	1,344	$4.95	$4.95	$5.50	$5.50	2	4	7	2	5	7	1	11.1%
Energy		MWH	255	1,472	1,727	$44.87	$44.87	$51.91	$51.91	11	66	77	13	76	90	12	15.7%
Opt Energy		MWH	3	107	110	$92.56	$44.87	$105.89	$51.91	0	5	5	0	6	6	1	15.6%
Fuel Cost		MWH	257	1,580	1,837	$31.00	$26.99	$31.76	$27.64	8	43	51	8	44	52	1	2.4%
Riders		MWH	257	1,580	1,837	$6.27	$6.27	$1.19	$1.19	2	10	12	0	2	2	-9	-81.0%
Total:										23	128	151	24	132	157	6	3.7%
A06 Limited Off-Peak ResReg Secondary																	
Cust Chg		Bills	1,477	2,956	4,433	$4.95	$4.95	$5.50	$5.50	7	15	22	8	16	24	2	11.1%
Energy	On	MWH	21	81	102	$360.00	$360.00	$405.00	$405.00	8	29	37	9	33	41	5	12.5%
Energy	Off	MWH	207	2,362	2,569	$36.65	$36.65	$44.28	$44.28	8	87	94	9	105	114	20	20.8%
Fuel Cost		MWH	228	2,443	2,671	$30.62	$26.65	$30.38	$26.45	7	65	72	7	65	72	-1	-0.8%
Riders		MWH	228	2,443	2,671	$6.39	$6.39	$1.19	$1.19	1	16	17	0	3	3	-14	-81.4%
Total:										31	211	242	33	221	254	12	5.0%
A06 Limited Off-Peak ResSH Secondary																	
Cust Chg		Bills	24	48	72	$4.95	$4.95	$5.50	$5.50	0	0	0	0	0	0	0	11.1%
Energy	On	MWH	0	1	1	$360.00	$360.00	$405.00	$405.00	0	0	0	0	0	0	0	12.5%
Energy	Off	MWH	26	89	115	$36.65	$36.65	$44.28	$44.28	1	3	4	1	4	5	1	20.8%
Fuel Cost		MWH	26	90	116	$30.62	$26.65	$30.38	$26.45	1	2	3	1	2	3	0	-0.8%
Riders		MWH	26	90	116	$6.39	$6.39	$1.19	$1.19	0	1	1	0	0	0	-1	-81.4%
Total:										2	7	9	2	7	9	0	3.7%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units Summer	Billing Units Winter	Billing Units Annual	Present Rate Summer	Present Rate Winter	Proposed Rate Summer	Proposed Rate Winter	Present Revenues Summer	Present Revenues Winter	Present Revenues Annual	Proposed Revenues Summer	Proposed Revenues Winter	Proposed Revenues Annual	Increase Annual	Pct Inc. Annual
A06 Limited Off-Peak Sm C&I Secondary																	
Cust Chg		Bills	205	410	615	$10.00	$10.00	$11.00	$11.00	2	4	6	2	5	7	1	10.0%
Cust Chg		Bills	143	284	427	$13.60	$13.60	$15.00	$15.00	2	4	6	2	4	6	1	10.3%
Cust Chg		Bills	0	0	0	$60.00	$60.00	$60.00	$60.00	0	0	0	0	0	0	0	0.0%
Energy	On	MWH	49	92	141	$360.00	$360.00	$405.00	$405.00	18	33	51	20	37	57	6	12.5%
Energy	Off	MWH	28	624	652	$36.65	$36.65	$44.28	$44.28	1	23	24	1	28	29	5	20.8%
Energy	Off	MWH	301	740	1,041	$36.65	$36.65	$44.28	$44.28	11	27	38	13	33	46	8	20.8%
Energy	Off	MWH	0	0	0	$35.60	$35.60	$43.13	$43.13	0	0	0	0	0	0	0	0.0%
Fuel Cost		MWH	377	1,456	1,834	$31.00	$26.99	$31.76	$27.64	12	39	51	12	40	52	1	2.4%
Riders		MWH	377	1,456	1,834	$6.27	$6.27	$1.19	$1.19	2	9	11	0	2	2	-9	-81.0%
Total:										48	139	187	51	148	200	12	6.6%
A09 SmallGen UnMtrd Sm C&I Secondary																	
Cust Chg		Bills	400	800	1,200	$8.78	$8.78	$10.24	$10.24	4	7	11	4	8	12	2	16.7%
Energy		MWH	8	16	24	$92.56	$77.57	$105.89	$89.98	1	1	2	1	1	2	0	15.4%
Fuel Cost		MWH	8	16	24	$31.00	$26.99	$31.76	$27.64	0	0	1	0	0	1	0	2.4%
Riders		MWH	8	16	24	$6.27	$6.27	$1.19	$1.19	0	0	0	0	0	0	0	-81.0%
Total:										5	9	13	5	10	15	2	14.7%
A10 SmallGen Sm C&I Secondary																	
Cust Chg		Bills	299,530	598,708	898,238	$10.78	$10.78	$12.24	$12.24	3,229	6,454	9,683	3,667	7,331	10,998	1,315	13.6%
Energy		MWH	253,978	505,620	759,598	$92.56	$77.57	$105.89	$89.98	23,508	39,221	62,729	26,894	45,496	72,389	9,660	15.4%
SvrSwtchAC		Tons	146,725	0	146,725	-$5.00	$0.00	-$5.00	$0.00	-734	0	-734	-734	0	-734	0	0.0%
Fuel Cost		MWH	253,978	505,620	759,598	$31.00	$26.99	$31.76	$27.64	7,874	13,646	21,519	8,065	13,978	22,043	524	2.4%
Riders		MWH	253,978	505,620	759,598	$6.27	$6.27	$1.19	$1.19	1,592	3,169	4,761	303	602	905	-3,856	-81.0%
Total:										35,469	62,490	97,959	38,195	67,406	105,602	7,643	7.8%
A40 Small Mun Pumping Public Auth Secondary																	
Cust Chg		Bills	3,721	7,442	11,163	$10.78	$10.78	$12.24	$12.24	40	80	120	46	91	137	16	13.6%
Energy		MWH	2,239	4,883	7,123	$92.56	$77.57	$105.89	$89.98	207	379	586	237	439	677	90	15.4%
Fuel Cost		MWH	2,239	4,883	7,123	$31.00	$26.99	$31.76	$27.64	69	132	201	71	135	206	5	2.4%
Riders		MWH	2,239	4,883	7,123	$6.27	$6.27	$1.19	$1.19	14	31	45	3	6	8	-36	-81.0%
Total:										331	621	952	356	671	1,028	76	7.9%
A11 WtrHeating Sm C&I Secondary																	
Cust Chg		Bills	320	637	957	$0.00	$0.00	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Energy		MWH	68	150	219	$92.56	$77.57	$105.89	$89.98	6	12	18	7	14	21	3	15.4%
Fuel Cost		MWH	68	150	219	$31.00	$26.99	$31.76	$27.64	2	4	6	2	4	6	0	2.4%
Riders		MWH	68	150	219	$6.27	$6.27	$1.19	$1.19	0	1	1	0	0	0	-1	-81.0%
Total:										9	17	26	9	18	27	2	7.1%
A13 Direct Current Sm C&I Secondary																	
Cust Chg		Bills	12	24	36	$10.78	$10.78	$12.24	$12.24	0	0	0	0	0	0	0	13.6%
Energy		MWH	1	2	3	$92.56	$77.57	$105.89	$89.98	0	0	0	0	0	0	0	15.4%
Demand		KW	676	1,352	2,028	$3.61	$3.61	$3.95	$3.95	2	5	7	3	5	8	1	9.4%
Fuel Cost		MWH	1	2	3	$31.00	$26.99	$31.76	$27.64	0	0	0	0	0	0	0	2.4%
Riders		MWH	1	2	3	$6.27	$6.27	$1.19	$1.19	0	0	0	0	0	0	0	-81.0%
Total:										3	5	8	3	6	9	1	9.5%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
		Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A12 SmallGen TOD Sm C&I Secondary																
Cust Chg	Bills	11,623	23,234	34,857	$12.78	$12.78	$14.24	$14.24	149	297	445	166	331	496	51	11.5%
Energy On	MWH	3,633	9,193	12,827	$148.80	$117.23	$167.86	$134.42	541	1,078	1,618	610	1,236	1,846	227	14.0%
Energy Off	MWH	7,443	19,023	26,467	$41.70	$41.70	$49.58	$49.58	310	793	1,104	369	943	1,312	209	18.9%
SvrSwtchAC	Tons	766	0	766	-$5.00	$0.00	-$5.00	$0.00	-4	0	-4	-4	0	-4	0	0.0%
Fuel Cost	MWH	11,077	28,217	39,293	$31.00	$26.99	$31.76	$27.64	343	762	1,105	352	780	1,132	27	2.4%
Riders	MWH	11,077	28,217	39,293	$6.27	$6.27	$1.19	$1.19	69	177	246	13	34	47	-199	-81.0%
Total:									1,409	3,106	4,515	1,506	3,324	4,829	314	7.0%
A16 SGS TOD kWh Mtr Sm C&I Secondary																
Cust Chg	Bills	12,245	24,474	36,719	$10.78	$10.78	$12.24	$12.24	132	264	396	150	300	450	54	13.6%
Energy	MWH	4,485	9,846	14,331	$79.19	$68.14	$90.98	$79.27	355	671	1,026	408	780	1,189	162	15.8%
Fuel Cost	MWH	4,485	9,846	14,331	$31.00	$26.99	$31.76	$27.64	139	266	405	142	272	415	10	2.4%
Riders	MWH	4,485	9,846	14,331	$6.27	$6.27	$1.19	$1.19	28	62	90	5	12	17	-73	-81.0%
Total:									654	1,262	1,916	706	1,364	2,070	153	8.0%
A18 SGS TOD UnMtrd Sm C&I Secondary																
Cust Chg	Bills	17,393	34,765	52,158	$8.78	$8.78	$10.24	$10.24	153	305	458	178	356	534	76	16.7%
Energy	MWH	8,799	17,916	26,715	$79.19	$68.14	$90.98	$79.27	697	1,221	1,918	801	1,420	2,221	303	15.8%
Fuel Cost	MWH	8,799	17,916	26,715	$31.00	$26.99	$31.76	$27.64	273	484	756	279	495	775	18	2.4%
Riders	MWH	8,799	17,916	26,715	$6.27	$6.27	$1.19	$1.19	55	112	167	10	21	32	-136	-81.0%
Total:									1,177	2,122	3,299	1,269	2,293	3,562	262	8.0%
A22 SGS TOD Low Watt Sm C&I Secondary																
Cust Chg	Bills	2,963	5,924	8,887	$0.00	$0.00	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
LwWattSm	Bills	72,592	145,184	217,776	$0.30	$0.30	$0.32	$0.32	22	44	65	23	46	70	4	6.7%
LwWattLg	Bills	168	336	504	$1.20	$1.20	$1.28	$1.28	0	0	1	0	0	1	0	6.7%
Energy	MWH	754	1,523	2,276	$79.19	$68.14	$90.98	$79.27	60	104	163	69	121	189	26	15.8%
Fuel Cost	MWH	754	1,523	2,276	$31.00	$26.99	$31.76	$27.64	23	41	64	24	42	66	2	2.4%
Riders	MWH	754	1,523	2,276	$6.27	$6.27	$1.19	$1.19	5	10	14	1	2	3	-12	-81.0%
Total:									110	198	308	117	212	328	20	6.6%
A14 General Sm C&I Secondary																
Cust Chg	Bills	165,996	331,795	497,791	$27.98	$27.98	$28.75	$28.75	4,645	9,284	13,928	4,772	9,538	14,310	382	2.7%
Energy	MWH	2,690,402	4,858,076	7,548,478	$34.07	$34.07	$39.48	$39.48	91,662	165,515	257,177	106,217	191,797	298,014	40,837	15.9%
Energy Cr	MWH	126,303	280,707	407,010	-$15.18	-$15.18	-$16.60	-$16.60	-1,917	-4,261	-6,178	-2,097	-4,660	-6,756	-578	9.4%
SvrSwtchAC	Tons	435,935	0	435,935	-$5.00	$0.00	-$5.00	$0.00	-2,180	0	-2,180	-2,180	0	-2,180	0	0.0%
Demand	KW	8,543,722	14,970,388	23,514,110	$14.79	$10.49	$16.54	$12.04	126,362	157,039	283,401	141,313	180,243	321,557	38,156	13.5%
BIS Rdr	KW	1,535	3,793	5,328	-$5.92	-$4.20	-$6.62	-$4.82	-9	-16	-25	-10	-18	-28	-3	13.7%
Fuel Cost	MWH	2,690,402	4,858,076	7,548,478	$27.57	$27.57	$27.64	$27.64	74,178	133,943	208,121	74,366	134,282	208,648	527	0.3%
Riders	KW	8,543,722	14,970,388	23,514,110	$1.04	$1.04	$0.00	$0.00	8,914	15,619	24,533	0	0	0	-24,533	-100.0%
Riders	MWH	2,690,402	4,858,076	7,548,478	$2.68	$2.68	$1.19	$1.19	7,211	13,020	20,231	3,205	5,787	8,992	-11,240	-55.6%
Total:									308,864	490,143	799,007	325,586	516,969	842,555	43,548	5.5%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
		Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A14 General Lg C&I Secondary																
Cust Chg	Bills	168	336	504	$27.98	$27.98	$28.75	$28.75	5	9	14	5	10	14	0	2.7%
Energy	MWH	48,381	90,251	138,632	$34.07	$34.07	$39.48	$39.48	1,648	3,075	4,723	1,910	3,563	5,473	750	15.9%
Energy Cr	MWH	4,915	9,152	14,067	-$15.18	-$15.18	-$16.60	-$16.60	-75	-139	-214	-82	-152	-234	-20	9.4%
SvrSwtchAC	Tons	293,332	0	293,332	-$5.00	$0.00	-$5.00	$0.00	-1,467	0	-1,467	-1,467	0	-1,467	0	0.0%
Demand	KW	129,687	237,510	367,197	$14.79	$10.49	$16.54	$12.04	1,918	2,491	4,410	2,145	2,860	5,005	595	13.5%
Fuel Cost	MWH	48,381	90,251	138,632	$27.57	$27.57	$27.64	$27.64	1,334	2,488	3,822	1,337	2,495	3,832	10	0.3%
Riders	KW	129,687	237,510	367,197	$1.04	$1.04	$0.00	$0.00	135	248	383	0	0	0	-383	-100.0%
Riders	MWH	48,381	90,251	138,632	$2.68	$2.68	$1.19	$1.19	130	242	372	58	108	165	-206	-55.6%
Total:									3,629	8,415	12,044	3,907	8,883	12,789	746	6.2%
A41 Municipal Pumping Public Auth Secondary																
Cust Chg	Bills	2,264	4,528	6,792	$27.98	$27.98	$28.75	$28.75	63	127	190	65	130	195	5	2.7%
Energy	MWH	24,400	34,950	59,349	$34.07	$34.07	$39.48	$39.48	831	1,191	2,022	963	1,380	2,343	321	15.9%
Energy Cr	MWH	1,923	1,924	3,846	-$15.18	-$15.18	-$16.60	-$16.60	-29	-29	-58	-32	-32	-64	-5	9.4%
Demand	KW	96,536	150,287	246,823	$14.79	$10.49	$16.54	$12.04	1,428	1,577	3,004	1,597	1,809	3,406	402	13.4%
Fuel Cost	MWH	24,400	34,950	59,349	$27.57	$27.57	$27.64	$27.64	673	964	1,636	674	966	1,640	4	0.3%
Riders	KW	96,536	150,287	246,823	$1.04	$1.04	$0.00	$0.00	101	157	258	0	0	0	-258	-100.0%
Riders	MWH	24,400	34,950	59,349	$2.68	$2.68	$1.19	$1.19	65	94	159	29	42	71	-88	-55.6%
Total:									3,132	4,079	7,211	3,297	4,295	7,592	381	5.3%
A14 General Sm C&I Primary																
Cust Chg	Bills	516	1,032	1,548	$27.98	$27.98	$28.75	$28.75	14	29	43	15	30	44	1	2.7%
Energy	MWH	39,033	72,660	111,693	$33.02	$33.02	$38.33	$38.33	1,289	2,399	3,688	1,496	2,785	4,281	593	16.1%
Energy Cr	MWH	1,519	4,580	6,099	-$15.18	-$15.18	-$16.60	-$16.60	-23	-70	-93	-25	-76	-101	-9	9.4%
SvrSwtchAC	Tons	3,108	0	3,108	-$5.00	$0.00	-$5.00	$0.00	-16	0	-16	-16	0	-16	0	0.0%
Demand	KW	123,889	210,357	334,246	$13.99	$9.69	$15.94	$11.44	1,733	2,038	3,772	1,975	2,406	4,381	610	16.2%
Fuel Cost	MWH	39,033	72,660	111,693	$27.57	$27.57	$27.64	$27.64	1,076	2,003	3,079	1,079	2,008	3,087	8	0.3%
Riders	KW	123,889	210,357	334,246	$1.04	$1.04	$0.00	$0.00	129	219	349	0	0	0	-349	-100.0%
Riders	MWH	39,033	72,660	111,693	$2.68	$2.68	$1.19	$1.19	105	195	299	46	87	133	-166	-55.6%
Total:									4,308	6,815	11,123	4,570	7,240	11,811	688	6.2%
A14 General Lg C&I Primary																
Cust Chg	Bills	16	32	48	$27.98	$27.98	$28.75	$28.75	0	1	1	0	1	1	0	2.7%
Energy	MWH	7,423	9,101	16,524	$33.02	$33.02	$38.33	$38.33	245	301	546	285	349	633	88	16.1%
Energy Cr	MWH	380	933	1,314	-$15.18	-$15.18	-$16.60	-$16.60	-6	-14	-20	-6	-15	-22	-2	9.4%
SvrSwtchAC	Tons	0	0	0	-$5.00	$0.00	-$5.00	$0.00	0	0	0	0	0	0	0	0.0%
Demand	KW	26,105	30,484	56,589	$13.99	$9.69	$15.94	$11.44	365	295	661	416	349	765	104	15.8%
Fuel Cost	MWH	7,423	9,101	16,524	$27.57	$27.57	$27.64	$27.64	205	251	456	205	252	457	1	0.3%
Riders	KW	26,105	30,484	56,589	$1.04	$1.04	$0.00	$0.00	27	32	59	0	0	0	-59	-100.0%
Riders	MWH	7,423	9,101	16,524	$2.68	$2.68	$1.19	$1.19	20	24	44	9	11	20	-25	-55.6%
Total:									857	890	1,747	909	945	1,854	108	6.2%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
		Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A41 Municipal Pumping Public Auth Primary																
Cust Chg	Bills	32	64	96	$27.98	$27.98	$28.75	$28.75	1	2	3	1	2	3	0	2.7%
Energy	MWH	550	911	1,461	$33.02	$33.02	$38.33	$38.33	18	30	48	21	35	56	8	16.1%
Energy Cr	MWH	3	7	10	-$15.18	-$15.18	-$16.60	-$16.60	0	0	0	0	0	0	0	9.4%
Demand	KW	2,526	4,465	6,991	$13.99	$9.69	$15.94	$11.44	35	43	79	40	51	91	13	16.2%
Fuel Cost	MWH	550	911	1,461	$27.57	$27.57	$27.64	$27.64	15	25	40	15	25	40	0	0.3%
Riders	KW	2,526	4,465	6,991	$1.04	$1.04	$0.00	$0.00	3	5	7	0	0	0	-7	-100.0%
Riders	MWH	550	911	1,461	$2.68	$2.68	$1.19	$1.19	1	2	4	1	1	2	-2	-55.6%
Total:									74	107	181	78	114	192	11	6.2%
A14 General Sm C&I Tr Transformed																
Cust Chg	Bills	4	8	12	$27.98	$27.98	$28.75	$28.75	0	0	0	0	0	0	0	2.7%
Energy	MWH	390	3,836	4,227	$31.40	$31.40	$36.66	$36.66	12	120	133	14	141	155	22	16.7%
Energy Cr	MWH	0	0	0	-$15.18	-$15.18	-$16.60	-$16.60	0	0	0	0	0	0	0	0.0%
Demand	KW	0	13,340	13,340	$13.24	$8.94	$14.84	$10.34	0	119	119	0	138	138	19	15.7%
Fuel Cost	MWH	390	3,836	4,227	$27.57	$27.57	$27.64	$27.64	11	106	117	11	106	117	0	0.3%
Riders	KW	0	13,340	13,340	$1.04	$1.04	$0.00	$0.00	0	14	14	0	0	0	-14	-100.0%
Riders	MWH	390	3,836	4,227	$2.68	$2.68	$1.19	$1.19	1	10	11	0	5	5	-6	-55.6%
Total:									24	370	394	26	389	415	21	5.3%
A14 General Lg C&I Tr Transformed																
Cust Chg	Bills	0	0	0	$27.98	$27.98	$28.75	$28.75	0	0	0	0	0	0	0	0.0%
Energy	MWH	0	0	0	$31.40	$31.40	$36.66	$36.66	0	0	0	0	0	0	0	0.0%
Energy Cr	MWH	0	0	0	-$15.18	-$15.18	-$16.60	-$16.60	0	0	0	0	0	0	0	0.0%
Demand	KW	0	0	0	$13.24	$8.94	$14.84	$10.34	0	0	0	0	0	0	0	0.0%
Fuel Cost	MWH	0	0	0	$27.57	$27.57	$27.64	$27.64	0	0	0	0	0	0	0	0.0%
Riders	KW	0	0	0	$1.04	$1.04	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Riders	MWH	0	0	0	$2.68	$2.68	$1.19	$1.19	0	0	0	0	0	0	0	0.0%
Total:									0	0	0	0	0	0	0	0.0%
A14 General Sm C&I Transmission																
Cust Chg	Bills	4	8	12	$27.98	$27.98	$28.75	$28.75	0	0	0	0	0	0	0	2.7%
Energy	MWH	23	46	69	$31.30	$31.30	$36.56	$36.56	1	1	2	1	2	3	0	16.8%
Energy Cr	MWH	0	0	0	-$15.18	-$15.18	-$16.60	-$16.60	0	0	0	0	0	0	0	0.0%
Demand	KW	222	420	642	$12.44	$8.14	$14.04	$9.54	3	3	6	3	4	7	1	15.3%
Fuel Cost	MWH	23	46	69	$27.57	$27.57	$27.64	$27.64	1	1	2	1	1	2	0	0.3%
Riders	KW	222	420	642	$1.04	$1.04	$0.00	$0.00	0	0	1	0	0	0	-1	-100.0%
Riders	MWH	23	46	69	$2.68	$2.68	$1.19	$1.19	0	0	0	0	0	0	0	-55.6%
Total:									5	7	11	5	7	12	1	4.8%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A15 General TOD Sm C&I Secondary																	
Cust Chg		Bills	17,470	34,919	52,389	$31.98	$31.98	$32.75	$32.75	559	1,117	1,675	572	1,143	1,716	40	2.4%
Energy	On	MWH	341,946	585,806	927,752	$48.55	$48.55	$56.11	$56.11	16,601	28,441	45,042	19,187	32,870	52,056	7,014	15.6%
Energy	Off	MWH	536,167	949,362	1,485,529	$23.41	$23.41	$27.37	$27.37	12,552	22,225	34,776	14,675	25,984	40,659	5,883	16.9%
Energy Cr		MWH	148,484	285,883	434,367	-$15.18	-$15.18	-$16.60	-$16.60	-2,254	-4,340	-6,594	-2,465	-4,746	-7,210	-617	9.4%
SvrSwtchAC		Tons	30,147	0	30,147	-$5.00	$0.00	-$5.00	$0.00	-151	0	-151	-151	0	-151	0	0.0%
Demand		KW	1,917,093	3,262,401	5,179,495	$14.79	$10.49	$16.54	$12.04	28,354	34,223	62,576	31,709	39,279	70,988	8,412	13.4%
Off Dmd		KW	51,903	114,788	166,691	$2.35	$2.35	$2.50	$2.50	122	270	392	130	287	417	25	6.4%
BIS Rdr		KW	0	0	0	-$5.92	-$4.20	-$6.62	-$4.82	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	341,946	585,806	927,752	$34.48	$34.48	$34.55	$34.55	11,791	20,199	31,989	11,813	20,237	32,050	61	0.2%
Fuel Cost	Off	MWH	536,167	949,362	1,485,529	$22.55	$22.55	$22.61	$22.61	12,091	21,409	33,500	12,122	21,464	33,587	87	0.3%
Riders		KW	1,917,093	3,262,401	5,179,495	$1.04	$1.04	$0.00	$0.00	2,000	3,404	5,404	0	0	0	-5,404	-100.0%
Riders		MWH	878,113	1,535,167	2,413,281	$2.68	$2.68	$1.19	$1.19	2,353	4,115	6,468	1,046	1,829	2,875	-3,593	-55.6%
Total:										84,018	131,061	215,079	88,638	138,348	226,986	11,907	5.5%
A15 General TOD Lg C&I Secondary																	
Cust Chg		Bills	804	1,608	2,412	$31.98	$31.98	$32.75	$32.75	26	51	77	26	53	79	2	2.4%
Energy	On	MWH	262,480	442,666	705,146	$48.55	$48.55	$56.11	$56.11	12,743	21,491	34,235	14,728	24,838	39,566	5,331	15.6%
Energy	Off	MWH	378,744	655,600	1,034,344	$23.41	$23.41	$27.37	$27.37	8,866	15,348	24,214	10,366	17,944	28,310	4,096	16.9%
Energy Cr		MWH	107,566	195,514	303,080	-$15.18	-$15.18	-$16.60	-$16.60	-1,633	-2,968	-4,601	-1,786	-3,246	-5,031	-430	9.4%
SvrSwtchAC		Tons	76,974	0	76,974	-$5.00	$0.00	-$5.00	$0.00	-385	0	-385	-385	0	-385	0	0.0%
Demand		KW	1,393,760	2,326,030	3,719,790	$14.79	$10.49	$16.54	$12.04	20,614	24,400	45,014	23,053	28,005	51,058	6,044	13.4%
Off Dmd		KW	16,474	49,483	65,957	$2.35	$2.35	$2.50	$2.50	39	116	155	41	124	165	10	6.4%
BIS Rdr		KW	14,631	30,240	44,871	-$5.92	-$4.20	-$6.62	-$4.82	-87	-127	-213	-97	-146	-242	-29	13.6%
AreaDevRdr		KW	0	0	0	-$2.96	-$2.10	-$3.31	-$2.41	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	262,480	442,666	705,146	$34.48	$34.48	$34.55	$34.55	9,050	15,263	24,314	9,068	15,292	24,360	46	0.2%
Fuel Cost	Off	MWH	378,744	655,600	1,034,344	$22.55	$22.55	$22.61	$22.61	8,541	14,784	23,325	8,563	14,823	23,386	61	0.3%
Riders		KW	1,393,760	2,326,030	3,719,790	$1.04	$1.04	$0.00	$0.00	1,454	2,427	3,881	0	0	0	-3,881	-100.0%
Riders		MWH	641,224	1,098,266	1,739,490	$2.68	$2.68	$1.19	$1.19	1,719	2,944	4,662	764	1,308	2,072	-2,590	-55.6%
Total:										60,948	93,730	154,678	64,342	98,996	163,337	8,659	5.6%
A15 General TOD Sm C&I Primary																	
Cust Chg		Bills	304	604	908	$31.98	$31.98	$32.75	$32.75	10	19	29	10	20	30	1	2.4%
Energy	On	MWH	21,530	34,027	55,557	$47.50	$47.50	$54.96	$54.96	1,023	1,616	2,639	1,183	1,870	3,053	414	15.7%
Energy	Off	MWH	33,026	53,724	86,750	$22.36	$22.36	$26.22	$26.22	738	1,201	1,940	866	1,409	2,275	335	17.3%
Energy Cr		MWH	9,745	14,365	24,111	-$15.18	-$15.18	-$16.60	-$16.60	-148	-218	-366	-162	-238	-400	-34	9.4%
SvrSwtchAC		Tons	2,643	0	2,643	-$5.00	$0.00	-$5.00	$0.00	-13	0	-13	-13	0	-13	0	0.0%
Demand		KW	124,949	203,363	328,312	$13.99	$9.69	$15.94	$11.44	1,748	1,971	3,719	1,992	2,326	4,318	600	16.1%
Off Dmd		KW	9,146	12,806	21,951	$1.55	$1.55	$1.90	$1.90	14	20	34	17	24	42	8	22.6%
BIS Rdr		KW	0	0	0	-$5.60	-$3.88	-$6.38	-$4.58	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	21,530	34,027	55,557	$34.48	$34.48	$34.55	$34.55	742	1,173	1,916	744	1,175	1,919	4	0.2%
Fuel Cost	Off	MWH	33,026	53,724	86,750	$22.55	$22.55	$22.61	$22.61	745	1,212	1,956	747	1,215	1,961	5	0.3%
Riders		KW	124,949	203,363	328,312	$1.04	$1.04	$0.00	$0.00	130	212	343	0	0	0	-343	-100.0%
Riders		MWH	54,556	87,751	142,307	$2.68	$2.68	$1.19	$1.19	146	235	381	65	105	170	-212	-55.6%
Total:										5,136	7,441	12,577	5,449	7,906	13,354	777	6.2%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A15 General TOD Lg C&I Primary																	
Cust Chg		Bills	412	824	1,236	$31.98	$31.98	$32.75	$32.75	13	26	40	13	27	40	1	2.4%
Energy		MWH	300,933	480,993	781,926	$47.50	$47.50	$54.96	$54.96	14,295	22,848	37,142	16,540	26,436	42,975	5,833	15.7%
Energy	On	MWH	461,994	765,188	1,227,182	$22.36	$22.36	$26.22	$26.22	10,331	17,110	27,441	12,114	20,064	32,178	4,737	17.3%
Energy Cr	Off	MWH	152,579	272,157	424,736	-$15.18	-$15.18	-$16.60	-$16.60	-2,316	-4,131	-6,447	-2,533	-4,518	-7,051	-603	9.4%
SvrSwtchAC		Tons	2,724	0	2,724	-$5.00	$0.00	-$5.00	$0.00	-14	0	-14	-14	0	-14	0	0.0%
Demand		KW	1,572,031	2,524,062	4,096,093	$13.99	$9.69	$15.94	$11.44	21,993	24,458	46,451	25,058	28,875	53,933	7,483	16.1%
Off Dmd		KW	30,410	91,920	122,330	$1.55	$1.55	$1.90	$1.90	47	142	190	58	175	232	43	22.6%
BIS Rdr		KW	9,200	19,889	29,089	-$5.60	-$3.88	-$6.38	-$4.58	-51	-77	-129	-59	-91	-150	-21	16.4%
Fuel Cost	On	MWH	300,933	480,993	781,926	$34.48	$34.48	$34.55	$34.55	10,376	16,585	26,961	10,396	16,616	27,012	51	0.2%
Fuel Cost	Off	MWH	461,994	765,188	1,227,182	$22.55	$22.55	$22.61	$22.61	10,418	17,256	27,674	10,445	17,300	27,746	72	0.3%
Riders		KW	1,572,031	2,524,062	4,096,093	$1.04	$1.04	$0.00	$0.00	1,640	2,633	4,274	0	0	0	-4,274	-100.0%
Riders		MWH	762,927	1,246,181	2,009,108	$2.68	$2.68	$1.19	$1.19	2,045	3,340	5,385	909	1,484	2,393	-2,992	-55.6%
Total:										68,777	100,190	168,967	72,928	106,369	179,297	10,330	6.1%
A29 Light Rail Sm C&I Primary																	
Cust Chg		Bills	64	128	192	$102.34	$102.34	$101.75	$101.75	7	13	20	7	13	20	0	-0.6%
Energy	On	MWH	3,223	7,189	10,413	$47.50	$47.50	$54.96	$54.96	153	341	495	177	395	572	78	15.7%
Energy	Off	MWH	3,875	9,873	13,748	$22.36	$22.36	$26.22	$26.22	87	221	307	102	259	360	53	17.3%
Energy Cr		MWH	1,304	2,877	4,181	-$13.03	-$13.03	-$14.20	-$14.20	-17	-37	-54	-19	-41	-59	-5	9.0%
Demand		KW	14,752	36,393	51,146	$8.71	$4.41	$9.10	$4.60	128	160	289	134	167	302	13	4.4%
Trans Dmd		KW	20,824	49,959	70,783	$5.28	$5.28	$6.84	$6.84	110	264	374	142	342	484	110	29.5%
Off Dmd		KW	1,354	2,555	3,910	$1.55	$1.55	$1.90	$1.90	2	4	6	3	5	7	1	22.6%
Fuel Cost	On	MWH	3,223	7,189	10,413	$34.48	$34.48	$34.55	$34.55	111	248	359	111	248	360	1	0.2%
Fuel Cost	Off	MWH	3,875	9,873	13,748	$22.55	$22.55	$22.61	$22.61	87	223	310	88	223	311	1	0.3%
Riders		KW	20,824	49,959	70,783	$1.04	$1.04	$0.00	$0.00	22	52	74	0	0	0	-74	-100.0%
Riders		MWH	7,099	17,062	24,161	$2.68	$2.68	$1.19	$1.19	19	46	65	8	20	29	-36	-55.6%
Total:										709	1,535	2,244	753	1,632	2,386	142	6.3%
A15 General TOD Sm C&I Transmission																	
Cust Chg		Bills	4	8	12	$31.98	$31.98	$32.75	$32.75	0	0	0	0	0	0	0	2.4%
Energy	On	MWH	38	78	116	$45.78	$45.78	$53.19	$53.19	2	4	5	2	4	6	1	16.2%
Energy	Off	MWH	0	0	0	$20.64	$20.64	$24.45	$24.45	0	0	0	0	0	0	0	0.0%
Energy Cr		MWH	10	14	24	-$15.18	-$15.18	-$16.60	-$16.60	0	0	0	0	0	0	0	9.4%
SvrSwtchAC		Tons	0	0	0	-$5.00	$0.00	-$5.00	$0.00	0	0	0	0	0	0	0	0.0%
Demand		KW	209	907	1,116	$12.44	$8.14	$14.04	$9.54	3	7	10	3	9	12	2	16.1%
Off Dmd		KW	0	0	0	$0.00	$0.00	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	38	78	116	$34.48	$34.48	$34.55	$34.55	1	3	4	1	3	4	0	0.2%
Fuel Cost	Off	MWH	0	0	0	$22.55	$22.55	$22.61	$22.61	0	0	0	0	0	0	0	0.0%
Riders		KW	209	907	1,116	$1.04	$1.04	$0.00	$0.00	0	1	1	0	0	0	-1	-100.0%
Riders		MWH	38	78	116	$2.68	$2.68	$1.19	$1.19	0	0	0	0	0	0	0	-55.6%
Total:										6	15	21	6	16	22	1	5.3%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A15 General TOD Lg C&I Tr Transformed																	
Cust Chg		Bills	24	48	72	$31.98	$31.98	$32.75	$32.75	1	2	2	1	2	2	0	2.4%
Energy	On	MWH	160,138	258,488	418,627	$45.88	$45.88	$53.29	$53.29	7,347	11,859	19,207	8,533	13,774	22,307	3,100	16.1%
Energy	Off	MWH	268,648	454,561	723,209	$20.74	$20.74	$24.55	$24.55	5,572	9,428	14,999	6,594	11,158	17,752	2,753	18.4%
Energy Cr		MWH	162,534	275,524	438,058	-$15.18	-$15.18	-$16.60	-$16.60	-2,467	-4,182	-6,650	-2,698	-4,574	-7,272	-622	9.4%
SvrSwtchAC		Tons	752	0	752	-$5.00	$0.00	-$5.00	$0.00	-4	0	-4	-4	0	-4	0	0.0%
Demand		KW	696,262	1,120,323	1,816,585	$13.24	$8.94	$14.84	$10.34	9,219	10,016	19,234	10,333	11,584	21,917	2,682	13.9%
Off Dmd		KW	1,104	8,754	9,858	$0.80	$0.80	$0.80	$0.80	1	7	8	1	7	8	0	0.0%
Fuel Cost	On	MWH	160,138	258,488	418,627	$34.48	$34.48	$34.55	$34.55	5,522	8,913	14,434	5,532	8,930	14,462	27	0.2%
Fuel Cost	Off	MWH	268,648	454,561	723,209	$22.55	$22.55	$22.61	$22.61	6,058	10,251	16,309	6,074	10,277	16,351	42	0.3%
Riders		KW	696,262	1,120,323	1,816,585	$1.04	$1.04	$0.00	$0.00	726	1,169	1,895	0	0	0	-1,895	-100.0%
Riders		MWH	428,786	713,050	1,141,836	$2.68	$2.68	$1.19	$1.19	1,149	1,911	3,060	511	849	1,360	-1,700	-55.6%
Total:										33,124	49,372	82,496	34,877	52,007	86,883	4,388	5.3%
A15 General TOD Lg C&I Transmission																	
Cust Chg		Bills	12	24	36	$31.98	$31.98	$32.75	$32.75	0	1	1	0	1	1	0	2.4%
Energy	On	MWH	7,632	12,567	20,199	$45.78	$45.78	$53.19	$53.19	349	575	925	406	668	1,074	150	16.2%
Energy	Off	MWH	13,079	18,513	31,591	$20.64	$20.64	$24.45	$24.45	270	382	652	320	453	772	120	18.4%
Energy Cr		MWH	0	235	235	-$15.18	-$15.18	-$16.60	-$16.60	0	-4	-4	0	-4	-4	0	9.4%
Demand		KW	61,437	83,145	144,583	$12.44	$8.14	$14.04	$9.54	764	677	1,441	863	793	1,656	215	14.9%
Off Dmd		KW	0	0	0	$0.00	$0.00	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	7,632	12,567	20,199	$34.48	$34.48	$34.55	$34.55	263	433	696	264	434	698	1	0.2%
Fuel Cost	Off	MWH	13,079	18,513	31,591	$22.55	$22.55	$22.61	$22.61	295	417	712	296	419	714	2	0.3%
Riders		KW	61,437	83,145	144,583	$1.04	$1.04	$0.00	$0.00	64	87	151	0	0	0	-151	-100.0%
Riders		MWH	20,711	31,080	51,791	$2.68	$2.68	$1.19	$1.19	56	83	139	25	37	62	-77	-55.6%
Total:										2,062	2,652	4,714	2,173	2,801	4,973	259	5.5%
A23 Peak-Ctrl Tier Sm C&I Secondary																	
Cust Chg		Bills	5,443	10,879	16,322	$57.34	$57.34	$61.75	$61.75	312	624	936	336	672	1,008	72	7.7%
Energy		MWH	347,272	659,940	1,007,212	$34.07	$34.07	$39.48	$39.48	11,832	22,484	34,316	13,710	26,054	39,765	5,449	15.9%
Energy Cr		MWH	11,695	22,536	34,231	-$15.18	-$15.18	-$16.60	-$16.60	-178	-342	-520	-194	-374	-568	-49	9.4%
Demand		KW	517,177	1,008,167	1,525,344	$14.79	$10.49	$16.54	$12.04	7,649	10,576	18,225	8,554	12,138	20,692	2,468	13.5%
Control Dmd		KW	326,835	511,959	838,794	$8.88	$8.88	$10.41	$10.41	2,902	4,546	7,448	3,402	5,329	8,732	1,283	17.2%
Control Dmd		KW	220,990	341,753	562,742	$7.86	$7.86	$9.28	$9.28	1,737	2,686	4,423	2,051	3,171	5,222	799	18.1%
Control Dmd		KW	182,785	317,376	500,161	$7.34	$7.34	$8.74	$8.74	1,342	2,330	3,671	1,598	2,774	4,371	700	19.1%
Control Dmd		KW	11,117	19,770	30,888	$7.15	$7.15	$8.54	$8.54	79	141	221	95	169	264	43	19.4%
Control Dmd		KW	42,691	78,011	120,703	$6.56	$6.56	$7.92	$7.92	280	512	792	338	618	956	164	20.7%
Control Dmd		KW	2,608	5,947	8,555	$6.09	$6.09	$7.42	$7.42	16	36	52	19	44	63	11	21.8%
AnnMinDmd		KW	39,935	79,870	119,805	$1.00	$1.00	$1.19	$1.19	40	80	120	48	95	143	23	19.0%
Fuel Cost		MWH	347,272	659,940	1,007,212	$27.57	$27.57	$27.64	$27.64	9,575	18,195	27,770	9,599	18,241	27,840	70	0.3%
Riders		KW	1,304,203	2,282,983	3,587,186	$1.04	$1.04	$0.00	$0.00	1,361	2,382	3,743	0	0	0	-3,743	-100.0%
Riders		MWH	347,272	659,940	1,007,212	$2.68	$2.68	$1.19	$1.19	931	1,769	2,700	414	786	1,200	-1,500	-55.6%
Total:										37,878	66,019	103,896	39,970	69,719	109,688	5,792	5.6%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
		Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A23 Peak-Ctrl Tier Lg C&I Secondary																
Cust Chg	Bills	16	32	48	$57.34	$57.34	$61.75	$61.75	1	2	3	1	2	3	0	7.7%
Energy	MWH	5,320	8,909	14,229	$34.07	$34.07	$39.48	$39.48	181	304	485	210	352	562	77	15.9%
Energy Cr	MWH	477	889	1,366	-$15.18	-$15.18	-$16.60	-$16.60	-7	-13	-21	-8	-15	-23	-2	9.4%
Demand	KW	3,007	4,637	7,644	$14.79	$10.49	$16.54	$12.04	44	49	93	50	56	106	12	13.4%
Control Dmd	KW	3,426	4,588	8,014	$8.88	$8.88	$10.41	$10.41	30	41	71	36	48	83	12	17.2%
Control Dmd	KW	3,356	4,237	7,593	$7.86	$7.86	$9.28	$9.28	26	33	60	31	39	70	11	18.1%
Control Dmd	KW	6,613	10,743	17,355	$7.34	$7.34	$8.74	$8.74	49	79	127	58	94	152	24	19.1%
Control Dmd	KW	0	0	0	$7.15	$7.15	$8.54	$8.54	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	682	1,113	1,796	$6.56	$6.56	$7.92	$7.92	4	7	12	5	9	14	2	20.7%
Control Dmd	KW	0	0	0	$6.09	$6.09	$7.42	$7.42	0	0	0	0	0	0	0	0.0%
Fuel Cost	MWH	5,320	8,909	14,229	$27.57	$27.57	$27.64	$27.64	147	246	392	147	246	393	1	0.3%
Riders	KW	17,084	25,318	42,401	$1.04	$1.04	$0.00	$0.00	18	26	44	0	0	0	-44	-100.0%
Riders	MWH	5,320	8,909	14,229	$2.68	$2.68	$1.19	$1.19	14	24	38	6	11	17	-21	-55.6%
Total:									508	797	1,305	536	841	1,378	73	5.6%
A23 Peak-Ctrl Tier Sm C&I Primary																
Cust Chg	Bills	180	360	540	$57.34	$57.34	$61.75	$61.75	10	21	31	11	22	33	2	7.7%
Energy	MWH	22,333	46,163	68,495	$33.02	$33.02	$38.33	$38.33	737	1,524	2,262	856	1,769	2,626	364	16.1%
Energy Cr	MWH	520	1,636	2,156	-$15.18	-$15.18	-$16.60	-$16.60	-8	-25	-33	-9	-27	-36	-3	9.4%
Demand	KW	28,631	59,547	88,178	$13.99	$9.69	$15.94	$11.44	401	577	978	456	681	1,138	160	16.4%
Control Dmd	KW	26,059	44,683	70,742	$8.08	$8.08	$9.81	$9.81	211	361	572	256	438	694	122	21.4%
Control Dmd	KW	9,370	17,624	26,994	$7.06	$7.06	$8.68	$8.68	66	124	191	81	153	234	44	22.9%
Control Dmd	KW	13,716	16,511	30,226	$6.54	$6.54	$8.14	$8.14	90	108	198	112	134	246	48	24.5%
Control Dmd	KW	3,107	5,797	8,904	$6.35	$6.35	$7.94	$7.94	20	37	57	25	46	71	14	25.0%
Control Dmd	KW	2,015	5,738	7,754	$5.76	$5.76	$7.32	$7.32	12	33	45	15	42	57	12	27.1%
Control Dmd	KW	2,969	5,671	8,640	$5.29	$5.29	$6.82	$6.82	16	30	46	20	39	59	13	28.9%
Fuel Cost	MWH	22,333	46,163	68,495	$27.57	$27.57	$27.64	$27.64	616	1,273	1,889	617	1,276	1,893	5	0.3%
Riders	KW	85,867	155,571	241,438	$1.04	$1.04	$0.00	$0.00	90	162	252	0	0	0	-252	-100.0%
Riders	MWH	22,333	46,163	68,495	$2.68	$2.68	$1.19	$1.19	60	124	184	27	55	82	-102	-55.6%
Total:									2,319	4,349	6,668	2,467	4,629	7,096	428	6.4%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
		Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A23 Peak-Ctrl Tier Lg C&I Primary																
Cust Chg	Bills	0	0	0	$57.34	$57.34	$61.75	$61.75	0	0	0	0	0	0	0	0.0%
Energy	MWH	0	0	0	$33.02	$33.02	$38.33	$38.33	0	0	0	0	0	0	0	0.0%
Energy Cr	MWH	0	0	0	-$15.18	-$15.18	-$16.60	-$16.60	0	0	0	0	0	0	0	0.0%
Demand	KW	0	0	0	$13.99	$9.69	$15.94	$11.44	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$8.08	$8.08	$9.81	$9.81	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$7.06	$7.06	$8.68	$8.68	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$6.54	$6.54	$8.14	$8.14	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$6.35	$6.35	$7.94	$7.94	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$5.76	$5.76	$7.32	$7.32	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$5.29	$5.29	$6.82	$6.82	0	0	0	0	0	0	0	0.0%
Fuel Cost	MWH	0	0	0	$27.57	$27.57	$27.64	$27.64	0	0	0	0	0	0	0	0.0%
Riders	KW	0	0	0	$1.04	$1.04	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Riders	MWH	0	0	0	$2.68	$2.68	$1.19	$1.19	0	0	0	0	0	0	0	0.0%
Total:									0	0	0	0	0	0	0	0.0%
A23 Peak-Ctrl Tier Sm C&I Tr Transformed																
Cust Chg	Bills	0	0	0	$57.34	$57.34	$61.75	$61.75	0	0	0	0	0	0	0	0.0%
Energy	MWH	0	0	0	$31.40	$31.40	$36.66	$36.66	0	0	0	0	0	0	0	0.0%
Energy Cr	MWH	0	0	0	-$15.18	-$15.18	-$16.60	-$16.60	0	0	0	0	0	0	0	0.0%
Demand	KW	0	0	0	$13.24	$8.94	$14.84	$10.34	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$7.33	$7.33	$8.71	$8.71	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$6.31	$6.31	$7.58	$7.58	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$5.79	$5.79	$7.04	$7.04	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$5.60	$5.60	$6.84	$6.84	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$5.01	$5.01	$6.22	$6.22	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$4.54	$4.54	$5.72	$5.72	0	0	0	0	0	0	0	0.0%
Fuel Cost	MWH	0	0	0	$27.57	$27.57	$27.64	$27.64	0	0	0	0	0	0	0	0.0%
Riders	KW	0	0	0	$1.04	$1.04	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Riders	MWH	0	0	0	$2.68	$2.68	$1.19	$1.19	0	0	0	0	0	0	0	0.0%
Total:									0	0	0	0	0	0	0	0.0%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
		Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A23 Peak-Ctrl Tier Sm C&I Transmission																
Cust Chg	Bills	8	16	24	$57.34	$57.34	$61.75	$61.75	0	1	1	0	1	1	0	7.7%
Energy	MWH	1,120	2,283	3,403	$31.30	$31.30	$36.56	$36.56	35	71	106	41	83	124	18	16.8%
Energy Cr	MWH	0	0	0	-$15.18	-$15.18	-$16.60	-$16.60	0	0	0	0	0	0	0	0.0%
Demand	KW	203	420	624	$12.44	$8.14	$14.04	$9.54	3	3	6	3	4	7	1	15.4%
Control Dmd	KW	986	1,555	2,541	$6.53	$6.53	$7.91	$7.91	6	10	17	8	12	20	4	21.1%
Control Dmd	KW	0	0	0	$5.51	$5.51	$6.78	$6.78	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	2,928	6,258	9,186	$4.99	$4.99	$6.24	$6.24	15	31	46	18	39	57	11	25.1%
Control Dmd	KW	0	0	0	$4.80	$4.80	$6.04	$6.04	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$4.21	$4.21	$5.42	$5.42	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$3.74	$3.74	$4.92	$4.92	0	0	0	0	0	0	0	0.0%
Fuel Cost	MWH	1,120	2,283	3,403	$27.57	$27.57	$27.64	$27.64	31	63	94	31	63	94	0	0.3%
Riders	KW	4,117	8,233	12,351	$1.04	$1.04	$0.00	$0.00	4	9	13	0	0	0	-13	-100.0%
Riders	MWH	1,120	2,283	3,403	$2.68	$2.68	$1.19	$1.19	3	6	9	1	3	4	-5	-55.6%
Total:									97	195	292	103	206	308	16	5.5%
A23 Peak-Ctrl Tier Lg C&I Transmission																
Cust Chg	Bills	4	8	12	$57.34	$57.34	$61.75	$61.75	0	0	1	0	0	1	0	7.7%
Energy	MWH	1,332	2,692	4,024	$31.30	$31.30	$36.56	$36.56	42	84	126	49	98	147	21	16.8%
Energy Cr	MWH	0	0	0	-$15.18	-$15.18	-$16.60	-$16.60	0	0	0	0	0	0	0	0.0%
Demand	KW	124	260	384	$12.44	$8.14	$14.04	$9.54	2	2	4	2	2	4	1	15.4%
Control Dmd	KW	0	0	0	$6.53	$6.53	$7.91	$7.91	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$5.51	$5.51	$6.78	$6.78	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	4,092	7,954	12,046	$4.99	$4.99	$6.24	$6.24	20	40	60	26	50	75	15	25.1%
Control Dmd	KW	0	0	0	$4.80	$4.80	$6.04	$6.04	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$4.21	$4.21	$5.42	$5.42	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$3.74	$3.74	$4.92	$4.92	0	0	0	0	0	0	0	0.0%
Fuel Cost	MWH	1,332	2,692	4,024	$27.57	$27.57	$27.64	$27.64	37	74	111	37	74	111	0	0.3%
Riders	KW	4,215	8,215	12,430	$1.04	$1.04	$0.00	$0.00	4	9	13	0	0	0	-13	-100.0%
Riders	MWH	1,332	2,692	4,024	$2.68	$2.68	$1.19	$1.19	4	7	11	2	3	5	-6	-55.6%
Total:									109	217	325	115	229	343	18	5.6%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A24 Peak-Ctrl Tier TOD Sm C&I Secondary																	
Cust Chg		Bills	778	1,555	2,333	$57.34	$57.34	$61.75	$61.75	45	89	134	48	96	144	10	7.7%
Energy	On	MWH	58,552	104,953	163,505	$48.55	$48.55	$56.11	$56.11	2,843	5,095	7,938	3,285	5,889	9,174	1,236	15.6%
Energy	Off	MWH	90,958	165,769	256,726	$23.41	$23.41	$27.37	$27.37	2,129	3,881	6,010	2,490	4,537	7,027	1,017	16.9%
Energy Cr		MWH	25,188	47,114	72,302	-$15.18	-$15.18	-$16.60	-$16.60	-382	-715	-1,098	-418	-782	-1,200	-103	9.4%
Demand		KW	107,993	198,534	306,528	$14.79	$10.49	$16.54	$12.04	1,597	2,083	3,680	1,786	2,390	4,177	497	13.5%
Off Dmd		KW	8,123	25,973	34,097	$2.35	$2.35	$2.50	$2.50	19	61	80	20	65	85	5	6.4%
Control Dmd		KW	52,342	84,762	137,104	$8.88	$8.88	$10.41	$10.41	465	753	1,217	545	882	1,427	210	17.2%
Control Dmd		KW	41,026	72,725	113,751	$7.86	$7.86	$9.28	$9.28	322	572	894	381	675	1,056	162	18.1%
Control Dmd		KW	120,787	210,116	330,904	$7.34	$7.34	$8.74	$8.74	887	1,542	2,429	1,056	1,836	2,892	463	19.1%
Control Dmd		KW	3,888	7,392	11,281	$7.15	$7.15	$8.54	$8.54	28	53	81	33	63	96	16	19.4%
Control Dmd		KW	11,266	20,451	31,717	$6.56	$6.56	$7.92	$7.92	74	134	208	89	162	251	43	20.7%
Control Dmd		KW	0	0	0	$6.09	$6.09	$7.42	$7.42	0	0	0	0	0	0	0	0.0%
AnnMinDmd		KW	1,052	2,104	3,156	$1.00	$1.00	$1.19	$1.19	1	2	3	1	3	4	1	19.0%
Fuel Cost	On	MWH	58,552	104,953	163,505	$34.48	$34.48	$34.55	$34.55	2,019	3,619	5,638	2,023	3,626	5,648	11	0.2%
Fuel Cost	Off	MWH	90,958	165,769	256,726	$22.55	$22.55	$22.61	$22.61	2,051	3,738	5,789	2,056	3,748	5,804	15	0.3%
Riders		KW	337,302	593,982	931,284	$1.04	$1.04	$0.00	$0.00	352	620	972	0	0	0	-972	-100.0%
Riders		MWH	149,510	270,721	420,231	$2.68	$2.68	$1.19	$1.19	401	726	1,126	178	322	501	-626	-55.6%
Total:										12,850	22,252	35,102	13,574	23,513	37,086	1,985	5.7%
A24 Peak-Ctrl Tier TOD Lg C&I Secondary																	
Cust Chg		Bills	204	408	612	$57.34	$57.34	$61.75	$61.75	12	23	35	13	25	38	3	7.7%
Energy	On	MWH	58,377	104,646	163,023	$48.55	$48.55	$56.11	$56.11	2,834	5,081	7,915	3,276	5,872	9,147	1,232	15.6%
Energy	Off	MWH	87,388	156,185	243,573	$23.41	$23.41	$27.37	$27.37	2,046	3,656	5,702	2,392	4,275	6,667	965	16.9%
Energy Cr		MWH	23,517	40,830	64,347	-$15.18	-$15.18	-$16.60	-$16.60	-357	-620	-977	-390	-678	-1,068	-91	9.4%
Demand		KW	115,928	213,904	329,832	$14.79	$10.49	$16.54	$12.04	1,715	2,244	3,958	1,917	2,575	4,493	534	13.5%
Off Dmd		KW	4,345	7,778	12,123	$2.35	$2.35	$2.50	$2.50	10	18	28	11	19	30	2	6.4%
Control Dmd		KW	48,504	94,736	143,240	$8.88	$8.88	$10.41	$10.41	431	841	1,272	505	986	1,491	219	17.2%
Control Dmd		KW	23,617	45,740	69,357	$7.86	$7.86	$9.28	$9.28	186	360	545	219	424	644	98	18.1%
Control Dmd		KW	118,323	203,005	321,328	$7.34	$7.34	$8.74	$8.74	868	1,490	2,359	1,034	1,774	2,808	450	19.1%
Control Dmd		KW	5,489	10,071	15,561	$7.15	$7.15	$8.54	$8.54	39	72	111	47	86	133	22	19.4%
Control Dmd		KW	32,665	58,877	91,542	$6.56	$6.56	$7.92	$7.92	214	386	601	259	466	725	124	20.7%
Control Dmd		KW	0	0	0	$6.09	$6.09	$7.42	$7.42	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	58,377	104,646	163,023	$34.48	$34.48	$34.55	$34.55	2,013	3,608	5,621	2,017	3,615	5,632	11	0.2%
Fuel Cost	Off	MWH	87,388	156,185	243,573	$22.55	$22.55	$22.61	$22.61	1,971	3,522	5,493	1,976	3,531	5,507	14	0.3%
Riders		KW	344,526	626,333	970,860	$1.04	$1.04	$0.00	$0.00	359	653	1,013	0	0	0	-1,013	-100.0%
Riders		MWH	145,766	260,830	406,596	$2.68	$2.68	$1.19	$1.19	391	699	1,090	174	311	484	-605	-55.6%
Total:										12,732	22,034	34,766	13,448	23,283	36,731	1,965	5.7%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A24 Peak-Ctrl Tier TOD Sm C&I Primary																	
Cust Chg		Bills	68	136	204	$57.34	$57.34	$61.75	$61.75	4	8	12	4	8	13	1	7.7%
Energy	On	MWH	9,086	15,533	24,619	$47.50	$47.50	$54.96	$54.96	432	738	1,169	499	854	1,353	184	15.7%
Energy	Off	MWH	15,324	25,628	40,952	$22.36	$22.36	$26.22	$26.22	343	573	916	402	672	1,074	158	17.3%
Energy Cr		MWH	4,770	8,649	13,419	-$15.18	-$15.18	-$16.60	-$16.60	-72	-131	-204	-79	-144	-223	-19	9.4%
Demand		KW	19,000	31,463	50,463	$13.99	$9.69	$15.94	$11.44	266	305	571	303	360	663	92	16.1%
Off Dmd		KW	2,876	5,575	8,450	$1.55	$1.55	$1.90	$1.90	4	9	13	5	11	16	3	22.6%
Control Dmd		KW	7,184	15,522	22,706	$8.08	$8.08	$9.81	$9.81	58	125	183	70	152	223	39	21.4%
Control Dmd		KW	4,606	5,310	9,916	$7.06	$7.06	$8.68	$8.68	33	37	70	40	46	86	16	22.9%
Control Dmd		KW	16,662	26,993	43,655	$6.54	$6.54	$8.14	$8.14	109	177	286	136	220	355	70	24.5%
Control Dmd		KW	0	0	0	$6.35	$6.35	$7.94	$7.94	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	5,163	8,231	13,394	$5.76	$5.76	$7.32	$7.32	30	47	77	38	60	98	21	27.1%
Control Dmd		KW	0	0	0	$5.29	$5.29	$6.82	$6.82	0	0	0	0	0	0	0	0.0%
AnnMinDmdChg		KW	0	0	0	$1.00	$1.00	$1.19	$1.19	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	9,086	15,533	24,619	$34.48	$34.48	$34.55	$34.55	313	536	849	314	537	850	2	0.2%
Fuel Cost	Off	MWH	15,324	25,628	40,952	$22.55	$22.55	$22.61	$22.61	346	578	924	346	579	926	2	0.3%
Riders		KW	52,616	87,518	140,133	$1.04	$1.04	$0.00	$0.00	55	91	146	0	0	0	-146	-100.0%
Riders		MWH	24,410	41,162	65,571	$2.68	$2.68	$1.19	$1.19	65	110	176	29	49	78	-98	-55.6%
Total:										1,984	3,203	5,187	2,108	3,404	5,512	325	6.3%
A24 Peak-Ctrl Tier TOD Lg C&I Primary																	
Cust Chg		Bills	296	592	888	$57.34	$57.34	$61.75	$61.75	17	34	51	18	37	55	4	7.7%
Energy	On	MWH	173,041	302,807	475,849	$47.50	$47.50	$54.96	$54.96	8,220	14,384	22,603	9,511	16,643	26,153	3,550	15.7%
Energy	Off	MWH	268,118	473,154	741,272	$22.36	$22.36	$26.22	$26.22	5,995	10,580	16,576	7,030	12,407	19,437	2,861	17.3%
Energy Cr		MWH	75,970	151,419	227,389	-$15.18	-$15.18	-$16.60	-$16.60	-1,153	-2,299	-3,452	-1,261	-2,514	-3,775	-323	9.4%
Demand		KW	409,911	718,618	1,128,528	$13.99	$9.69	$15.94	$11.44	5,735	6,963	12,698	6,534	8,221	14,755	2,057	16.2%
Off Dmd		KW	12,590	26,366	38,957	$1.55	$1.55	$1.90	$1.90	20	41	60	24	50	74	14	22.6%
Control Dmd		KW	37,171	61,446	98,617	$8.08	$8.08	$9.81	$9.81	300	496	797	365	603	967	171	21.4%
Control Dmd		KW	82,965	139,347	222,311	$7.06	$7.06	$8.68	$8.68	586	984	1,570	720	1,210	1,930	360	22.9%
Control Dmd		KW	271,425	451,483	722,909	$6.54	$6.54	$8.14	$8.14	1,775	2,953	4,728	2,209	3,675	5,884	1,157	24.5%
Control Dmd		KW	39,544	60,023	99,566	$6.35	$6.35	$7.94	$7.94	251	381	632	314	477	791	158	25.0%
Control Dmd		KW	88,800	153,043	241,843	$5.76	$5.76	$7.32	$7.32	511	882	1,393	650	1,120	1,770	377	27.1%
Control Dmd		KW	50,260	102,833	153,094	$5.29	$5.29	$6.82	$6.82	266	544	810	343	701	1,044	234	28.9%
BIS Rdr		KW	5,316	12,717	18,033	-$3.08	-$2.13	-$3.51	-$2.52	-16	-27	-43	-19	-32	-51	-7	16.5%
Fuel Cost	On	MWH	173,041	302,807	475,849	$34.48	$34.48	$34.55	$34.55	5,967	10,441	16,408	5,978	10,461	16,439	31	0.2%
Fuel Cost	Off	MWH	268,118	473,154	741,272	$22.55	$22.55	$22.61	$22.61	6,046	10,670	16,716	6,062	10,698	16,760	43	0.3%
Riders		KW	980,076	1,686,793	2,666,869	$1.04	$1.04	$0.00	$0.00	1,023	1,760	2,782	0	0	0	-2,782	-100.0%
Riders		MWH	441,160	775,962	1,217,121	$2.68	$2.68	$1.19	$1.19	1,182	2,080	3,262	526	924	1,450	-1,812	-55.6%
Total:										36,724	60,867	97,591	39,004	64,680	103,683	6,093	6.2%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units Summer	Billing Units Winter	Billing Units Annual	Present Rate Summer	Present Rate Winter	Proposed Rate Summer	Proposed Rate Winter	Present Revenues Summer	Present Revenues Winter	Present Revenues Annual	Proposed Revenues Summer	Proposed Revenues Winter	Proposed Revenues Annual	Increase Annual	Pct Inc. Annual
A24 Peak-Ctrl Tier TOD Lg C&I Tr Transformed																	
Cust Chg		Bills	20	40	60	$57.34	$57.34	$61.75	$61.75	1	2	3	1	2	4	0	7.7%
Energy	On	MWH	47,558	89,257	136,814	$45.88	$45.88	$53.29	$53.29	2,182	4,095	6,277	2,534	4,756	7,290	1,013	16.1%
Energy	Off	MWH	76,887	146,100	222,987	$20.74	$20.74	$24.55	$24.55	1,595	3,030	4,625	1,887	3,586	5,473	849	18.4%
Energy Cr		MWH	27,035	53,061	80,096	-$15.18	-$15.18	-$16.60	-$16.60	-410	-805	-1,216	-449	-881	-1,330	-114	9.4%
Demand		KW	86,589	162,856	249,445	$13.24	$8.94	$14.84	$10.34	1,146	1,456	2,602	1,285	1,684	2,969	367	14.1%
Off Dmd		KW	2,458	5,114	7,572	$0.80	$0.80	$0.80	$0.80	2	4	6	2	4	6	0	0.0%
Control Dmd		KW	14,610	25,448	40,058	$7.33	$7.33	$8.71	$8.71	107	187	294	127	222	349	55	18.8%
Control Dmd		KW	0	0	0	$6.31	$6.31	$7.58	$7.58	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	51,208	94,267	145,475	$5.79	$5.79	$7.04	$7.04	296	546	842	361	664	1,024	182	21.6%
Control Dmd		KW	0	0	0	$5.60	$5.60	$6.84	$6.84	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$5.01	$5.01	$6.22	$6.22	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	99,043	184,110	283,153	$4.54	$4.54	$5.72	$5.72	450	836	1,286	567	1,053	1,620	334	26.0%
Fuel Cost	On	MWH	47,558	89,257	136,814	$34.48	$34.48	$34.55	$34.55	1,640	3,078	4,717	1,643	3,083	4,726	9	0.2%
Fuel Cost	Off	MWH	76,887	146,100	222,987	$22.55	$22.55	$22.61	$22.61	1,734	3,295	5,029	1,738	3,303	5,042	13	0.3%
Riders		KW	251,451	466,681	718,131	$1.04	$1.04	$0.00	$0.00	262	487	749	0	0	0	-749	-100.0%
Riders		MWH	124,445	235,357	359,801	$2.68	$2.68	$1.19	$1.19	334	631	964	148	280	429	-536	-55.6%
Total:										9,339	16,840	26,179	9,845	17,757	27,602	1,423	5.4%
A24 Peak-Ctrl Tier TOD Sm C&I Transmission																	
Cust Chg		Bills	0	0	0	$57.34	$57.34	$61.75	$61.75	0	0	0	0	0	0	0	0.0%
Energy	On	MWH	0	0	0	$45.78	$45.78	$53.19	$53.19	0	0	0	0	0	0	0	0.0%
Energy	Off	MWH	0	0	0	$20.64	$20.64	$24.45	$24.45	0	0	0	0	0	0	0	0.0%
Energy Cr		MWH	0	0	0	-$15.18	-$15.18	-$16.60	-$16.60	0	0	0	0	0	0	0	0.0%
Demand		KW	0	0	0	$12.44	$8.14	$14.04	$9.54	0	0	0	0	0	0	0	0.0%
Off Dmd		KW	0	0	0	$0.00	$0.00	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$6.53	$6.53	$7.91	$7.91	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$5.51	$5.51	$6.78	$6.78	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$4.99	$4.99	$6.24	$6.24	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$4.80	$4.80	$6.04	$6.04	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$4.21	$4.21	$5.42	$5.42	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$3.74	$3.74	$4.92	$4.92	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	0	0	0	$34.48	$34.48	$34.55	$34.55	0	0	0	0	0	0	0	0.0%
Fuel Cost	Off	MWH	0	0	0	$22.55	$22.55	$22.61	$22.61	0	0	0	0	0	0	0	0.0%
Riders		KW	0	0	0	$1.04	$1.04	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Riders		MWH	0	0	0	$2.68	$2.68	$1.19	$1.19	0	0	0	0	0	0	0	0.0%
Total:										0	0	0	0	0	0	0	0.0%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A24 Peak-Ctrl Tier TOD Lg C&I Transmission																	
Cust Chg		Bills	4	8	12	$57.34	$57.34	$61.75	$61.75	0	0	1	0	0	1	0	7.7%
Energy	On	MWH	462	1,102	1,564	$45.78	$45.78	$53.19	$53.19	21	50	72	25	59	83	12	16.2%
Energy	Off	MWH	1,233	2,527	3,761	$20.64	$20.64	$24.45	$24.45	25	52	78	30	62	92	14	18.4%
Energy Cr		MWH	0	39	39	-$15.18	-$15.18	-$16.60	-$16.60	0	-1	-1	0	-1	-1	0	9.4%
Demand		KW	0	0	0	$12.44	$8.14	$14.04	$9.54	0	0	0	0	0	0	0	0.0%
Off Dmd		KW	0	0	0	$0.00	$0.00	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$6.53	$6.53	$7.91	$7.91	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$5.51	$5.51	$6.78	$6.78	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$4.99	$4.99	$6.24	$6.24	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$4.80	$4.80	$6.04	$6.04	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	18,362	30,875	49,237	$4.21	$4.21	$5.42	$5.42	77	130	207	100	167	267	60	28.7%
Control Dmd		KW	0	0	0	$3.74	$3.74	$4.92	$4.92	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	462	1,102	1,564	$34.48	$34.48	$34.55	$34.55	16	38	54	16	38	54	0	0.2%
Fuel Cost	Off	MWH	1,233	2,527	3,761	$22.55	$22.55	$22.61	$22.61	28	57	85	28	57	85	0	0.3%
Riders		KW	18,362	30,875	49,237	$1.04	$1.04	$0.00	$0.00	19	32	51	0	0	0	-51	-100.0%
Riders		MWH	1,695	3,630	5,325	$2.68	$2.68	$1.19	$1.19	5	10	14	2	4	6	-8	-55.6%
Total:										192	369	561	200	387	587	26	4.7%
A27 Energy-Control Rider Sm C&I Secondary																	
Cust Chg		Bills	16	32	48	$57.34	$57.34	$61.75	$61.75	1	2	3	1	2	3	0	7.7%
Energy	On	MWH	56	116	172	$48.55	$48.55	$56.11	$56.11	3	6	8	3	7	10	1	15.6%
Energy	OnC	MWH	1,615	2,844	4,459	$46.47	$46.47	$54.14	$54.14	75	132	207	87	154	241	34	16.5%
Energy	Off	MWH	100	213	313	$23.41	$23.41	$27.37	$27.37	2	5	7	3	6	9	1	16.9%
Energy	OffC	MWH	2,388	4,284	6,672	$22.80	$22.80	$27.11	$27.11	54	98	152	65	116	181	29	18.9%
Energy Cr		MWH	538	1,120	1,658	-$15.18	-$15.18	-$16.60	-$16.60	-8	-17	-25	-9	-19	-28	-2	9.4%
Demand		KW	227	467	694	$14.79	$10.49	$16.54	$12.04	3	5	8	4	6	9	1	13.6%
Off Dmd		KW	12	65	78	$2.35	$2.35	$2.50	$2.50	0	0	0	0	0	0	0	6.4%
Control Dmd		KW	0	0	0	$7.15	$7.15	$8.54	$8.54	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	7,068	10,971	18,039	$6.56	$6.56	$7.92	$7.92	46	72	118	56	87	143	25	20.7%
Control Dmd		KW	3,495	7,610	11,104	$6.09	$6.09	$7.42	$7.42	21	46	68	26	56	82	15	21.8%
Fuel Cost	On	MWH	1,671	2,960	4,631	$34.48	$34.48	$34.55	$34.55	58	102	160	58	102	160	0	0.2%
Fuel Cost	Off	MWH	2,488	4,496	6,985	$22.55	$22.55	$22.61	$22.61	56	101	158	56	102	158	0	0.3%
Riders		KW	10,790	19,048	29,838	$1.04	$1.04	$0.00	$0.00	11	20	31	0	0	0	-31	-100.0%
Riders		MWH	4,159	7,457	11,616	$2.68	$2.68	$1.19	$1.19	11	20	31	5	9	14	-17	-55.6%
Total:										334	592	926	355	628	983	56	6.1%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A27 Energy-Control Rider Lg C&I Secondary																	
Cust Chg		Bills	4	8	12	$57.34	$57.34	$61.75	$61.75	0	0	1	0	0	1	0	7.7%
Energy	On	MWH	0	0	0	$48.55	$48.55	$56.11	$56.11	0	0	0	0	0	0	0	0.0%
Energy	OnC	MWH	960	1,585	2,544	$46.47	$46.47	$54.14	$54.14	45	74	118	52	86	138	20	16.5%
Energy	Off	MWH	0	0	0	$23.41	$23.41	$27.37	$27.37	0	0	0	0	0	0	0	0.0%
Energy	OffC	MWH	1,613	2,635	4,248	$22.80	$22.80	$27.11	$27.11	37	60	97	44	71	115	18	18.9%
Energy Cr		MWH	677	1,057	1,734	-$15.18	-$15.18	-$16.60	-$16.60	-10	-16	-26	-11	-18	-29	-2	9.4%
Demand		KW	0	0	0	$14.79	$10.49	$16.54	$12.04	0	0	0	0	0	0	0	0.0%
Off Dmd		KW	5	27	31	$2.35	$2.35	$2.50	$2.50	0	0	0	0	0	0	0	6.4%
Control Dmd		KW	0	0	0	$7.15	$7.15	$8.54	$8.54	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	4,648	7,822	12,470	$6.56	$6.56	$7.92	$7.92	30	51	82	37	62	99	17	20.7%
Control Dmd		KW	0	0	0	$6.09	$6.09	$7.42	$7.42	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	960	1,585	2,544	$34.48	$34.48	$34.55	$34.55	33	55	88	33	55	88	0	0.2%
Fuel Cost	Off	MWH	1,613	2,635	4,248	$22.55	$22.55	$22.61	$22.61	36	59	96	36	60	96	0	0.3%
Riders		KW	4,648	7,822	12,470	$1.04	$1.04	$0.00	$0.00	5	8	13	0	0	0	-13	-100.0%
Riders		MWH	2,573	4,219	6,792	$2.68	$2.68	$1.19	$1.19	7	11	18	3	5	8	-10	-55.6%
Total:										183	303	486	194	322	516	30	6.1%
A27 Energy-Control Rider Sm C&I Primary																	
Cust Chg		Bills	4	8	12	$57.34	$57.34	$61.75	$61.75	0	0	1	0	0	1	0	7.7%
Energy	On	MWH	0	0	0	$47.50	$47.50	$54.96	$54.96	0	0	0	0	0	0	0	0.0%
Energy	OnC	MWH	1,678	3,237	4,915	$45.42	$45.42	$52.99	$52.99	76	147	223	89	172	260	37	16.7%
Energy	Off	MWH	0	0	0	$22.36	$22.36	$26.22	$26.22	0	0	0	0	0	0	0	0.0%
Energy	OffC	MWH	2,909	5,684	8,593	$21.75	$21.75	$25.96	$25.96	63	124	187	76	148	223	36	19.4%
Energy Cr		MWH	0	462	462	-$15.18	-$15.18	-$16.60	-$16.60	0	-7	-7	0	-8	-8	-1	9.4%
Demand		KW	0	0	0	$13.99	$9.69	$15.94	$11.44	0	0	0	0	0	0	0	0.0%
Off Dmd		KW	665	16	681	$1.55	$1.55	$1.90	$1.90	1	0	1	1	0	1	0	22.6%
Control Dmd		KW	0	0	0	$6.35	$6.35	$7.94	$7.94	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	7,068	10,971	18,039	$5.76	$5.76	$7.32	$7.32	41	63	104	52	80	132	28	27.1%
Control Dmd		KW	3,495	7,610	11,104	$5.29	$5.29	$6.82	$6.82	18	40	59	24	52	76	17	28.9%
Fuel Cost	On	MWH	1,678	3,237	4,915	$34.48	$34.48	$34.55	$34.55	58	112	169	58	112	170	0	0.2%
Fuel Cost	Off	MWH	2,909	5,684	8,593	$22.55	$22.55	$22.61	$22.61	66	128	194	66	129	194	1	0.3%
Riders		KW	10,562	18,581	29,143	$1.04	$1.04	$0.00	$0.00	11	19	30	0	0	0	-30	-100.0%
Riders		MWH	4,587	8,921	13,508	$2.68	$2.68	$1.19	$1.19	12	24	36	5	11	16	-20	-55.6%
Total:										347	651	997	371	695	1,066	68	6.9%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A27 Energy-Control Rider Lg C&I Primary																	
Cust Chg		Bills	12	24	36	$57.34	$57.34	$61.75	$61.75	1	1	2	1	1	2	0	7.7%
Energy	On	MWH	0	0	0	$47.50	$47.50	$54.96	$54.96	0	0	0	0	0	0	0	0.0%
Energy	OnC	MWH	4,323	8,299	12,622	$45.42	$45.42	$52.99	$52.99	196	377	573	229	440	669	96	16.7%
Energy	Off	MWH	0	0	0	$22.36	$22.36	$26.22	$26.22	0	0	0	0	0	0	0	0.0%
Energy	OffC	MWH	7,022	13,819	20,841	$21.75	$21.75	$25.96	$25.96	153	301	453	182	359	541	88	19.4%
Energy Cr		MWH	2,969	6,254	9,224	-$15.18	-$15.18	-$16.60	-$16.60	-45	-95	-140	-49	-104	-153	-13	9.4%
Demand		KW	0	0	0	$13.99	$9.69	$15.94	$11.44	0	0	0	0	0	0	0	0.0%
Off Dmd		KW	17	59	76	$1.55	$1.55	$1.90	$1.90	0	0	0	0	0	0	0	22.6%
Control Dmd		KW	0	678	678	$6.35	$6.35	$7.94	$7.94	0	4	4	0	5	5	1	25.0%
Control Dmd		KW	20,996	38,621	59,616	$5.76	$5.76	$7.32	$7.32	121	222	343	154	283	436	93	27.1%
Control Dmd		KW	0	0	0	$5.29	$5.29	$6.82	$6.82	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	4,323	8,299	12,622	$34.48	$34.48	$34.55	$34.55	149	286	435	149	287	436	1	0.2%
Fuel Cost	Off	MWH	7,022	13,819	20,841	$22.55	$22.55	$22.61	$22.61	158	312	470	159	312	471	1	0.3%
Riders		KW	20,996	39,299	60,295	$1.04	$1.04	$0.00	$0.00	22	41	63	0	0	0	-63	-100.0%
Riders		MWH	11,345	22,118	33,463	$2.68	$2.68	$1.19	$1.19	30	59	90	14	26	40	-50	-55.6%
Total:										785	1,509	2,294	838	1,610	2,448	154	6.7%
A27 Energy-Control Rider Lg C&I Tr Transformed																	
Cust Chg		Bills	8	16	24	$57.34	$57.34	$61.75	$61.75	0	1	1	0	1	1	0	7.7%
Energy	On	MWH	1,140	2,153	3,293	$45.88	$45.88	$53.29	$53.29	52	99	151	61	115	175	24	16.1%
Energy	OnC	MWH	42,254	77,832	120,086	$43.80	$43.80	$51.32	$51.32	1,851	3,409	5,260	2,168	3,994	6,162	903	17.2%
Energy	Off	MWH	2,154	3,946	6,100	$20.74	$20.74	$24.55	$24.55	45	82	127	53	97	150	23	18.4%
Energy	OffC	MWH	78,481	142,314	220,795	$20.13	$20.13	$24.29	$24.29	1,580	2,865	4,445	1,906	3,456	5,362	918	20.6%
Energy Cr		MWH	34,030	58,580	92,610	-$15.18	-$15.18	-$16.60	-$16.60	-517	-889	-1,406	-565	-972	-1,537	-132	9.4%
Demand		KW	4,532	8,501	13,033	$13.24	$8.94	$14.84	$10.34	60	76	136	67	88	155	19	14.1%
Off Dmd		KW	49,250	98,865	148,115	$0.80	$0.80	$0.80	$0.80	39	79	118	39	79	118	0	0.0%
Control Dmd		KW	0	0	0	$5.60	$5.60	$6.84	$6.84	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$5.01	$5.01	$6.22	$6.22	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	390,337	735,629	1,125,967	$4.54	$4.54	$5.72	$5.72	1,772	3,340	5,112	2,233	4,208	6,441	1,329	26.0%
Fuel Cost	On	MWH	43,394	79,985	123,379	$34.48	$34.48	$34.55	$34.55	1,496	2,758	4,254	1,499	2,763	4,262	8	0.2%
Fuel Cost	Off	MWH	80,634	146,260	226,895	$22.55	$22.55	$22.61	$22.61	1,818	3,298	5,117	1,823	3,307	5,130	13	0.3%
Riders		KW	394,869	744,130	1,139,000	$1.04	$1.04	$0.00	$0.00	412	776	1,188	0	0	0	-1,188	-100.0%
Riders		MWH	124,028	226,245	350,273	$2.68	$2.68	$1.19	$1.19	332	606	939	148	270	417	-522	-55.6%
Total:										8,942	16,500	25,442	9,433	17,405	26,837	1,396	5.5%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
Standby and Supplemental																	
Cust Chg	A14	Bills	4	8	12	$25.64	$25.64	$27.00	$27.00	0	0	0	0	0	0	0	5.3%
Cust Chg	A15	Bills	8	16	24	$25.64	$25.64	$27.00	$27.00	0	0	1	0	0	1	0	5.3%
Cust Chg	A15	Bills	8	16	24	$25.64	$25.64	$27.00	$27.00	0	0	1	0	0	1	0	5.3%
Cust Chg	A15	Bills	12	24	36	$25.64	$25.64	$27.00	$27.00	0	1	1	0	1	1	0	5.3%
Cust Chg	A15	Bills	8	16	24	$25.64	$25.64	$27.00	$27.00	0	0	1	0	0	1	0	5.3%
Cust Chg	A24	Bills	8	16	24	$25.64	$25.64	$27.00	$27.00	0	0	1	0	0	1	0	5.3%
Cust Chg	A24	Bills	4	8	12	$25.64	$25.64	$27.00	$27.00	0	0	0	0	0	0	0	5.3%
DemandU	A14	KW	2,000	4,000	6,000	$3.06	$3.06	$3.32	$3.32	6	12	18	7	13	20	2	8.5%
DemandU	A15	KW	2,532	5,064	7,596	$2.26	$2.26	$2.72	$2.72	6	11	17	7	14	21	3	20.4%
DemandU	A15	KW	12,000	24,000	36,000	$3.06	$3.06	$3.32	$3.32	37	73	110	40	80	120	9	8.5%
DemandU	A15	KW	8,000	16,000	24,000	$3.06	$3.06	$3.32	$3.32	24	49	73	27	53	80	6	8.5%
DemandU	A24	KW	13,000	26,000	39,000	$2.26	$2.26	$2.72	$2.72	29	59	88	35	71	106	18	20.4%
DemandS	A15	KW	20,000	40,000	60,000	$1.51	$1.51	$1.62	$1.62	30	60	91	32	65	97	7	7.3%
DemandS	A15	KW	269,858	457,527	727,385	$0.71	$0.71	$0.82	$0.82	192	325	516	221	375	596	80	15.5%
DemandS	A24	KW	16,000	32,000	48,000	$1.41	$1.41	$1.52	$1.52	23	45	68	24	49	73	5	7.8%
DmdSup	A15	KW	0	8,563	8,563	$1.85	$1.85	$2.02	$2.02	0	16	16	0	17	17	1	9.2%
DmdSup	A15	KW	28,000	56,000	84,000	$1.05	$1.05	$1.22	$1.22	29	59	88	34	68	102	14	16.2%
DmdSup	A24	KW	2,000	4,000	6,000	$2.60	$2.60	$3.12	$3.12	5	10	16	6	12	19	3	20.0%
DmdSup	A24	KW	14,000	24,500	38,500	$1.85	$1.85	$2.02	$2.02	26	45	71	28	49	78	7	9.2%
PkSurchg	A14	MWH	0	1	1	$63.12	$41.30	$71.24	$48.41	0	0	0	0	0	0	0	17.2%
PkSurchg	A15	MWH	13	43	55	$63.12	$41.30	$71.24	$48.41	1	2	3	1	2	3	0	15.9%
PkSurchg	A15	MWH	181	501	682	$63.12	$41.30	$71.24	$48.41	11	21	32	13	24	37	5	15.7%
PkSurchg	A15	MWH	4,015	7,817	11,832	$63.12	$41.30	$71.24	$48.41	253	323	576	286	378	664	88	15.3%
PkSurchg	A15	MWH	0	346	346	$63.12	$41.30	$71.24	$48.41	0	14	14	0	17	17	2	17.2%
PkSurchg	A15	MWH	1,454	975	2,429	$63.12	$41.30	$71.24	$48.41	92	40	132	104	47	151	19	14.2%
PkSurchg	A15	MWH	0	0	0	$63.12	$41.30	$71.24	$48.41	0	0	0	0	0	0	0	0.0%
Riders	A14	KW	2,000	4,000	6,000	$1.04	$1.04	$0.00	$0.00	2	4	6	0	0	0	-6	-100.0%
Riders	A15	KW	2,532	5,064	7,596	$1.04	$1.04	$0.00	$0.00	3	5	8	0	0	0	-8	-100.0%
Riders	A15	KW	12,000	24,000	36,000	$1.04	$1.04	$0.00	$0.00	13	25	38	0	0	0	-38	-100.0%
Riders	A15	KW	8,000	16,000	24,000	$1.04	$1.04	$0.00	$0.00	8	17	25	0	0	0	-25	-100.0%
Riders	A24	KW	13,000	26,000	39,000	$1.04	$1.04	$0.00	$0.00	14	27	41	0	0	0	-41	-100.0%
Riders	A15	KW	20,000	40,000	60,000	$1.04	$1.04	$0.00	$0.00	21	42	63	0	0	0	-63	-100.0%
Riders	A15	KW	269,858	457,527	727,385	$1.04	$1.04	$0.00	$0.00	282	477	759	0	0	0	-759	-100.0%
Riders	A24	KW	16,000	32,000	48,000	$1.04	$1.04	$0.00	$0.00	17	33	50	0	0	0	-50	-100.0%
Riders	A15	KW	0	8,563	8,563	$1.04	$1.04	$0.00	$0.00	0	9	9	0	0	0	-9	-100.0%
Riders	A15	KW	28,000	56,000	84,000	$1.04	$1.04	$0.00	$0.00	29	58	88	0	0	0	-88	-100.0%
Riders	A24	KW	2,000	4,000	6,000	$1.04	$1.04	$0.00	$0.00	2	4	6	0	0	0	-6	-100.0%
Riders	A24	KW	14,000	24,500	38,500	$1.04	$1.04	$0.00	$0.00	15	26	40	0	0	0	-40	-100.0%
Total:										1,170	1,896	3,066	867	1,338	2,205	-861	-28.1%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
PV Demand Credit Rider																	
Cust Chg	A14	Bills	200	400	600	$25.75	$25.75	$27.00	$27.00	5	10	15	5	11	16	1	4.9%
Cust Chg	A14	Bills	40	80	120	$25.75	$25.75	$27.00	$27.00	1	2	3	1	2	3	0	4.9%
Cust Chg	A15	Bills	120	240	360	$25.75	$25.75	$27.00	$27.00	3	6	9	3	6	10	0	4.9%
Cust Chg	A15	Bills	40	80	120	$25.75	$25.75	$27.00	$27.00	1	2	3	1	2	3	0	4.9%
Dmd Credit	A14	MWH	3,432	3,109	6,542	-$71.39	-$71.39	-$71.39	-$71.39	-245	-222	-467	-245	-222	-467	0	0.0%
Dmd Credit	A14	MWH	686	622	1,308	-$71.39	-$71.39	-$71.39	-$71.39	-49	-44	-93	-49	-44	-93	0	0.0%
Dmd Credit	A15	MWH	2,059	1,866	3,925	-$71.39	-$71.39	-$71.39	-$71.39	-147	-133	-280	-147	-133	-280	0	0.0%
Dmd Credit	A15	MWH	686	622	1,308	-$71.39	-$71.39	-$71.39	-$71.39	-49	-44	-93	-49	-44	-93	0	0.0%
Total:										-480	-423	-903	-479	-422	-902	2	-0.2%
A62 Real Time Pricing Lg C&I Primary																	
Cust Chg		Bills	12	24	36	$302.34	$302.34	$32.75	$32.75	4	7	11	0	1	1	-10	-89.2%
Energy		MWH	0	0	0	$0.00	$0.00	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Energy Cr		MWH	1,130	2,772	3,903	-$11.43	-$11.43	$0.00	$0.00	-13	-32	-45	0	0	0	45	-100.0%
Energy Cr		MWH	649	1,850	2,499	$0.00	$0.00	-$16.60	-$16.60	0	0	0	-11	-31	-41	-41	0.0%
LtdSurChg		MWH	52	103	155	$200.00	$200.00	$0.00	$0.00	10	21	31	0	0	0	-31	-100.0%
Demand		KW	17,242	28,645	45,887	$9.94	$9.94	$15.94	$11.44	171	285	456	306	384	690	234	51.3%
Dist Dmd		KW	29,829	49,557	79,386	$0.97	$0.97	$1.90	$1.90	29	48	77	3	5	8	-69	-90.2%
Energy		KW	2,689	4,867	7,556	$37.70	$27.15	$54.96	$54.96	101	132	234	148	267	415	182	77.8%
Energy		KW	4,897	8,927	13,824	$37.70	$27.15	$26.22	$26.22	185	242	427	128	234	362	-64	-15.1%
Fuel Cost	On	MWH	2,689	4,867	7,556	$34.48	$34.48	$34.55	$34.55	93	168	261	93	168	261	0	0.2%
Fuel Cost	Off	MWH	4,897	8,927	13,824	$22.55	$22.55	$22.61	$22.61	110	201	312	111	202	313	1	0.3%
Riders		KW	17,242	28,645	45,887	$1.04	$1.04	$0.00	$0.00	18	30	48	0	0	0	-48	-100.0%
Riders		MWH	7,587	13,794	21,380	$2.68	$2.68	$1.19	$1.19	20	37	57	9	16	25	-32	-55.6%
Total:										729	1,139	1,868	787	1,247	2,034	166	8.9%
A42 Siren Service Public Auth Secondary																	
HP		HP	15,204	30,408	45,612	$0.76	$0.76	$0.81	$0.81	12	23	35	12	25	37	2	6.6%
Total:										12	23	35	12	25	37	2	6.6%
Interdepartmental																	
Cust Chg			20	40	60	$0.00	$0.00	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Energy			3,295	3,813	7,108	$72.19	$67.25	$72.19	$67.25	238	256	494	238	256	494	0	0.0%
Fuel Cost			3,295	3,813	7,108	$27.57	$27.57	$27.64	$27.64	91	105	196	91	105	196	0	0.3%
Riders		MWH	3,295	3,813	7,108	$6.27	$6.27	$1.19	$1.19	21	24	45	4	5	8	-36	-81.0%
Total:										349	385	735	333	366	699	-36	-4.8%

[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS]

[HIGHLY CONFIDENTIAL TRADE SECRET ENDS]

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
		Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A07 Protective Ltg ResReg Secondary																
A100S	Lts	28,352	56,704	85,056	$7.34	$7.34	$8.10	$8.10	208	416	624	230	459	689	65	10.4%
A175M	Lts	10,960	21,920	32,880	$7.34	$7.34	$8.10	$8.10	80	161	241	89	178	266	25	10.4%
A250S	Lts	936	1,872	2,808	$11.64	$11.64	$12.95	$12.95	11	22	33	12	24	36	4	11.3%
A400M	Lts	252	504	756	$11.64	$11.64	$12.95	$12.95	3	6	9	3	7	10	1	11.3%
D250S	Lts	408	816	1,224	$12.62	$12.62	$13.50	$13.50	5	10	15	6	11	17	1	7.0%
D400S	Lts	112	224	336	$16.12	$16.12	$17.29	$17.29	2	4	5	2	4	6	0	7.3%
D400M	Lts	24	48	72	$16.19	$16.19	$17.34	$17.34	0	1	1	0	1	1	0	7.1%
D1000M	Lts	0	0	0	$25.52	$25.52	$26.55	$26.55	0	0	0	0	0	0	0	0.0%
Fuel Cost	MWH	1,632	4,618	6,249	$22.03	$22.03	$21.93	$21.93	36	102	138	36	101	137	-1	-0.4%
Riders	MWH	1,632	4,618	6,249	$2.68	$2.68	$1.19	$1.19	4	12	17	2	6	7	-9	-55.6%
Total:									350	734	1,084	379	790	1,170	86	7.9%
A07 Protective Ltg Sm C&I Secondary																
A100S	Lts	16,732	33,464	50,196	$7.34	$7.34	$8.10	$8.10	123	246	368	136	271	407	38	10.4%
A175M	Lts	6,800	13,600	20,400	$7.34	$7.34	$8.10	$8.10	50	100	150	55	110	165	16	10.4%
A250S	Lts	9,332	18,664	27,996	$11.64	$11.64	$12.95	$12.95	109	217	326	121	242	363	37	11.3%
A400M	Lts	3,868	7,736	11,604	$11.64	$11.64	$12.95	$12.95	45	90	135	50	100	150	15	11.3%
D250S	Lts	14,992	29,984	44,976	$12.62	$12.62	$13.50	$13.50	189	378	568	202	405	607	40	7.0%
D400S	Lts	20,312	40,624	60,936	$16.12	$16.12	$17.29	$17.29	327	655	982	351	702	1,054	71	7.3%
D400M	Lts	1,296	2,592	3,888	$16.19	$16.19	$17.34	$17.34	21	42	63	22	45	67	4	7.1%
D1000M	Lts	116	232	348	$25.52	$25.52	$26.55	$26.55	3	6	9	3	6	9	0	4.0%
Fuel Cost	MWH	6,066	17,471	23,537	$22.03	$22.03	$21.93	$21.93	134	385	518	133	383	516	-2	-0.4%
Riders	MWH	6,066	17,471	23,537	$2.68	$2.68	$1.19	$1.19	16	47	63	7	21	28	-35	-55.6%
Total:									1,017	2,166	3,182	1,081	2,285	3,366	184	5.8%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
		Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A30 St Ltg System Lighting Secondary																
OH70S	Lts	0	0	0	$9.63	$9.63	$12.18	$12.18	0	0	0	0	0	0	0	0.0%
OH100S	Lts	212	424	636	$10.17	$10.17	$12.76	$12.76	2	4	6	3	5	8	2	25.5%
OH150S	Lts	264	528	792	$10.95	$10.95	$13.78	$13.78	3	6	9	4	7	11	2	25.8%
OH200S	Lts	72	144	216	$12.88	$12.88	$15.63	$15.63	1	2	3	1	2	3	1	21.4%
OH250S	Lts	52	104	156	$13.87	$13.87	$16.74	$16.74	1	1	2	1	2	3	0	20.7%
OH400S	Lts	12	24	36	$16.85	$16.85	$20.27	$20.27	0	0	1	0	0	1	0	20.3%
OH175H	Lts	0	0	0	$14.98	$14.98	$17.08	$17.08	0	0	0	0	0	0	0	0.0%
OH40LED	Lts	204,912	409,824	614,736	$10.32	$10.32	$12.29	$12.29	2,115	4,229	6,344	2,518	5,037	7,555	1,211	19.1%
OH75LED	Lts	56,916	113,832	170,748	$11.01	$11.01	$12.98	$12.98	627	1,253	1,880	739	1,478	2,216	336	17.9%
OH165LED	Lts	11,044	22,088	33,132	$14.46	$14.46	$16.12	$16.12	160	319	479	178	356	534	55	11.5%
OH250LED	Lts	96	192	288	$17.98	$17.98	$19.54	$19.54	2	3	5	2	4	6	0	8.7%
UG70S	Lts	200	400	600	$19.54	$19.54	$22.81	$22.81	4	8	12	5	9	14	2	16.7%
UG100S	Lts	9,060	18,120	27,180	$20.07	$20.07	$23.39	$23.39	182	364	546	212	424	636	90	16.5%
UG150S	Lts	488	976	1,464	$20.86	$20.86	$24.42	$24.42	10	20	31	12	24	36	5	17.1%
UG250S	Lts	172	344	516	$23.38	$23.38	$27.15	$27.15	4	8	12	5	9	14	2	16.1%
UG400S	Lts	0	0	0	$26.06	$26.06	$30.52	$30.52	0	0	0	0	0	0	0	0.0%
UG175H	Lts	0	0	0	$27.90	$27.90	$31.16	$31.16	0	0	0	0	0	0	0	0.0%
UG40LED	Lts	75,828	151,656	227,484	$20.22	$20.22	$22.92	$22.92	1,533	3,066	4,600	1,738	3,476	5,214	614	13.4%
UG75LED	Lts	16,348	32,696	49,044	$20.91	$20.91	$23.61	$23.61	342	684	1,026	386	772	1,158	132	12.9%
UG165LED	Lts	3,636	7,272	10,908	$23.96	$23.96	$26.54	$26.54	87	174	261	96	193	289	28	10.8%
UG250LED	Lts	0	0	0	$27.19	$27.19	$29.80	$29.80	0	0	0	0	0	0	0	0.0%
Dec100S	Lts	280	560	840	$31.67	$31.67	$35.04	$35.04	9	18	27	10	20	29	3	10.6%
Dec150S	Lts	56	112	168	$32.84	$32.84	$36.27	$36.27	2	4	6	2	4	6	1	10.4%
Dec250S	Lts	216	432	648	$34.89	$34.89	$38.76	$38.76	8	15	23	8	17	25	3	11.1%
Dec400S	Lts	0	0	0	$37.38	$37.38	$42.02	$42.02	0	0	0	0	0	0	0	0.0%
PO70S	Lts	1,008	2,016	3,024	$5.97	$5.97	$6.56	$6.56	6	12	18	7	13	20	2	9.9%
PO100S	Lts	40,316	80,632	120,948	$6.66	$6.66	$7.34	$7.34	269	537	806	296	592	888	82	10.2%
PO150S	Lts	16,628	33,256	49,884	$7.54	$7.54	$8.35	$8.35	125	251	376	139	278	417	40	10.7%
PO250S	Lts	5,844	11,688	17,532	$9.61	$9.61	$10.70	$10.70	56	112	168	63	125	188	19	11.3%
PO400S	Lts	260	520	780	$12.42	$12.42	$13.89	$13.89	3	6	10	4	7	11	1	11.8%
PO175H	Lts	128	256	384	$13.54	$13.54	$14.91	$14.91	2	3	5	2	4	6	1	10.1%
PO40LED	Lts	2,432	4,864	7,296	$4.90	$4.90	$5.37	$5.37	12	24	36	13	26	39	3	9.6%
PO75LED	Lts	6,680	13,360	20,040	$5.49	$5.49	$6.04	$6.04	37	73	110	40	81	121	11	10.0%
PO165LED	Lts	2,292	4,584	6,876	$7.05	$7.05	$7.79	$7.79	16	32	48	18	36	54	5	10.5%
PO250LED	Lts	0	0	0	$8.93	$8.93	$9.91	$9.91	0	0	0	0	0	0	0	0.0%
POSurChg	Amt	39,188	78,377	117,565	$1.00	$1.00	$1.00	$1.00	39	78	118	39	78	118	0	0.0%
Fuel Cost	MWH	7,060	24,025	31,086	$22.03	$22.03	$21.93	$21.93	156	529	685	155	527	682	-3	-0.4%
Riders	MWH	7,060	24,025	31,086	$2.68	$2.68	$1.19	$1.19	19	64	83	8	29	37	-46	-55.6%
Total:									5,829	11,904	17,733	6,702	13,634	20,337	2,604	14.7%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
		Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A32 St Ltg Energy Lighting Secondary																
50S	Lts	15,364	30,728	46,092	$1.32	$1.32	$1.49	$1.49	20	41	61	23	46	69	8	12.9%
70S	Lts	49,980	99,960	149,940	$1.67	$1.67	$1.86	$1.86	83	167	250	93	186	279	28	11.4%
100S	Lts	40,724	81,448	122,172	$2.22	$2.22	$2.45	$2.45	90	181	271	100	200	299	28	10.4%
150S	Lts	18,220	36,440	54,660	$3.04	$3.04	$3.32	$3.32	55	111	166	60	121	181	15	9.2%
200S	Lts	5,988	11,976	17,964	$4.05	$4.05	$4.40	$4.40	24	49	73	26	53	79	6	8.6%
250S	Lts	23,212	46,424	69,636	$5.12	$5.12	$5.53	$5.53	119	238	357	128	257	385	29	8.0%
400S	Lts	3,784	7,568	11,352	$7.79	$7.79	$8.37	$8.37	29	59	88	32	63	95	7	7.4%
750S	Lts	184	368	552	$13.37	$13.37	$14.31	$14.31	2	5	7	3	5	8	1	7.0%
100M	Lts	308	616	924	$2.37	$2.37	$2.61	$2.61	1	1	2	1	2	2	0	10.1%
175M	Lts	2,276	4,552	6,828	$3.53	$3.53	$3.84	$3.84	8	16	24	9	17	26	2	8.8%
250M	Lts	380	760	1,140	$4.78	$4.78	$5.18	$5.18	2	4	5	2	4	6	0	8.4%
400M	Lts	1,332	2,664	3,996	$7.45	$7.45	$8.01	$8.01	10	20	30	11	21	32	2	7.5%
700M	Lts	216	432	648	$12.39	$12.39	$13.27	$13.27	3	5	8	3	6	9	1	7.1%
1000M	Lts	20	40	60	$17.24	$17.24	$18.43	$18.43	0	1	1	0	1	1	0	6.9%
1F72HO	Lts	36	72	108	$3.61	$3.61	$3.61	$3.61	0	0	0	0	0	0	0	0.0%
Fuel Cost	MWH	5,849	19,904	25,754	$22.03	$22.03	$21.93	$21.93	129	438	567	128	437	565	-2	-0.4%
Riders	MWH	5,849	19,904	25,754	$2.68	$2.68	$1.19	$1.19	16	53	69	7	24	31	-38	-55.6%
Total:									593	1,388	1,981	626	1,442	2,068	87	4.4%
A34 St Ltg Energy Mtrd Lighting Secondary																
Cust Chg	Bills	8,996	17,993	26,989	$5.00	$5.00	$5.50	$5.50	45	90	135	49	99	148	13	10.0%
Energy	MWH	7,972	27,129	35,101	$45.34	$45.34	$46.80	$46.80	361	1,230	1,591	373	1,270	1,643	51	3.2%
Fuel Cost	MWH	7,972	27,129	35,101	$22.03	$22.03	$21.93	$21.93	176	598	773	175	595	770	-3	-0.4%
Riders	MWH	7,972	27,129	35,101	$2.68	$2.68	$1.19	$1.19	21	73	94	9	32	42	-52	-55.6%
Total:									603	1,990	2,594	607	1,996	2,603	9	0.4%
A37 St Ltg St. Paul Lighting Secondary																
OH100S	Lts	4,308	8,616	12,924	$5.35	$5.35	$5.65	$5.65	23	46	69	24	49	73	4	5.6%
OH150S	Lts	2,376	4,752	7,128	$6.07	$6.07	$6.34	$6.34	14	29	43	15	30	45	2	4.4%
OH250S	Lts	4	8	12	$8.78	$8.78	$9.02	$9.02	0	0	0	0	0	0	0	2.7%
Fuel Cost	MWH	215	733	948	$22.03	$22.03	$21.93	$21.93	5	16	21	5	16	21	0	-0.4%
Riders	MWH	215	733	948	$2.68	$2.68	$1.19	$1.19	1	2	3	0	1	1	-1	-55.6%
Total:									43	93	136	44	96	140	4	3.2%
Retail + Interdepartmental Total:									1,212,765	1,908,375	3,121,140	1,297,066	2,024,616	3,321,682	200,542	6.4%
Interdepartmental without Base Increase:									349	385	735	333	366	699	-36	-4.8%
Retail:									1,212,415	1,907,989	3,120,405	1,296,733	2,024,250	3,320,983	200,578	6.4%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
		Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A01 Res OH ResReg Secondary																
Cust Chg	Bills	2,996,186	5,996,001	8,992,187	$8.55	$8.55	$10.08	$10.08	25,630	51,292	76,922	30,210	60,456	90,666	13,744	17.9%
Energy	MWH	1,716,559	2,701,965	4,418,524	$103.01	$88.03	$123.74	$107.22	176,823	237,854	414,677	212,407	289,705	502,112	87,435	21.1%
SvrSwtchAC	MWH	593,465	0	593,465	-$20.12	$0.00	-$10.00	$0.00	-11,938	0	-11,938	-7,381	0	-7,381	4,557	-38.2%
SvrSwtchWH	MWH	12,685	23,094	35,780	-$2.68	-$2.30	-$2.00	-$2.00	-34	-53	-87	-27	-49	-76	11	-13.0%
LowIncCredit	MWH	141,929	283,858	425,788	-$15.00	-$15.00	-$15.00	-$15.00	-2,129	-4,258	-6,387	-2,129	-4,258	-6,387	0	0.0%
Fuel Cost	MWH	1,716,559	2,701,965	4,418,524	$31.10	$27.07	$30.86	$26.86	53,384	73,152	126,536	52,970	72,584	125,554	-981	-0.8%
Riders	MWH	1,716,559	2,701,965	4,418,524	$6.16	$6.16	$1.19	$1.19	10,568	16,635	27,204	2,049	3,225	5,273	-21,930	-80.6%
Total:									252,304	374,622	626,926	288,098	421,663	709,761	82,835	13.2%
A01 Res OH ResSH Secondary																
Cust Chg	Bills	103,549	206,564	310,113	$10.55	$10.55	$12.08	$12.08	1,093	2,180	3,273	1,251	2,496	3,747	474	14.5%
Energy	MWH	53,573	187,084	240,657	$103.01	$59.88	$123.74	$73.58	5,519	11,203	16,721	6,629	13,766	20,395	3,674	22.0%
SvrSwtchAC	MWH	8,588	0	8,588	-$20.12	$0.00	-$10.00	$0.00	-173	0	-173	-89	0	-89	84	-48.5%
SvrSwtchWH	MWH	1,253	3,812	5,065	-$2.68	-$1.74	-$2.00	-$2.00	-3	-7	-10	-3	-8	-11	-1	7.5%
LowIncCredit	MWH	4,895	9,789	14,684	-$15.00	-$15.00	-$15.00	-$15.00	-73	-147	-220	-73	-147	-220	0	0.0%
Fuel Cost	MWH	53,573	187,084	240,657	$31.10	$27.07	$30.86	$26.86	1,666	5,065	6,731	1,653	5,026	6,679	-52	-0.8%
Riders	MWH	53,573	187,084	240,657	$6.16	$6.16	$1.19	$1.19	330	1,152	1,482	64	223	287	-1,194	-80.6%
Total:									8,358	19,446	27,804	9,432	21,356	30,788	2,984	10.7%
A03 Res UG ResReg Secondary																
Cust Chg	Bills	1,560,386	3,122,663	4,683,049	$10.55	$10.55	$12.08	$12.08	16,469	32,958	49,426	18,854	37,730	56,584	7,158	14.5%
Energy	MWH	1,339,262	2,052,347	3,391,609	$103.01	$88.03	$123.74	$107.22	137,957	180,668	318,625	165,720	220,053	385,773	67,147	21.1%
SvrSwtchAC	MWH	669,101	0	669,101	-$20.12	$0.00	-$10.00	$0.00	-13,460	0	-13,460	-7,385	0	-7,385	6,075	-45.1%
SvrSwtchWH	MWH	6,151	10,919	17,070	-$2.68	-$2.30	-$2.00	-$2.00	-16	-25	-42	-13	-23	-36	5	-13.0%
LowIncCredit	MWH	73,915	147,831	221,746	-$15.00	-$15.00	-$15.00	-$15.00	-1,109	-2,217	-3,326	-1,109	-2,217	-3,326	0	0.0%
Fuel Cost	MWH	1,339,262	2,052,347	3,391,609	$31.10	$27.07	$30.86	$26.86	41,650	55,564	97,214	41,327	55,133	96,461	-754	-0.8%
Riders	MWH	1,339,262	2,052,347	3,391,609	$6.16	$6.16	$1.19	$1.19	8,246	12,636	20,881	1,598	2,449	4,048	-16,834	-80.6%
Total:									189,737	279,583	469,320	218,993	313,125	532,118	62,798	13.4%
A03 Res UG ResSH Secondary																
Cust Chg	Bills	36,234	72,278	108,512	$12.55	$12.55	$14.08	$14.08	455	907	1,362	510	1,018	1,528	166	12.2%
Energy	MWH	25,898	90,440	116,338	$103.01	$59.88	$123.74	$73.58	2,668	5,416	8,083	3,205	6,655	9,859	1,776	22.0%
SvrSwtchAC	MWH	9,215	0	9,215	-$20.12	$0.00	-$10.00	$0.00	-185	0	-185	-92	0	-92	94	-50.6%
SvrSwtchWH	MWH	1,067	3,689	4,756	-$2.68	-$1.74	-$2.00	-$2.00	-3	-6	-9	-2	-8	-10	-1	8.7%
LowIncCredit	MWH	1,713	3,425	5,138	-$15.00	-$15.00	-$15.00	-$15.00	-26	-51	-77	-26	-51	-77	0	0.0%
Fuel Cost	MWH	25,898	90,440	116,338	$31.10	$27.07	$30.86	$26.86	805	2,449	3,254	799	2,430	3,229	-25	-0.8%
Riders	MWH	25,898	90,440	116,338	$6.16	$6.16	$1.19	$1.19	159	557	716	31	108	139	-577	-80.6%
Total:									3,874	9,270	13,144	4,426	10,151	14,576	1,432	10.9%
A00 WtrHeating ResSH Secondary																
Cust Chg	Bills	176	348	524	$0.00	$0.00	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Energy	MWH	26	92	118	$103.01	$88.03	$123.74	$107.22	3	8	11	3	10	13	2	21.4%
Fuel Cost	MWH	26	92	118	$31.10	$27.07	$30.86	$26.86	1	2	3	1	2	3	0	-0.8%
Riders	MWH	26	92	118	$6.16	$6.16	$1.19	$1.19	0	1	1	0	0	0	-1	-80.6%
Total:									4	11	15	4	12	17	2	11.4%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A02 Res TOD OH ResReg Secondary																	
Cust Chg		Bills	1,236	2,473	3,709	$10.55	$10.55	$12.08	$12.08	13	26	39	15	30	45	6	14.5%
Energy	On	MWH	292	543	835	$204.97	$165.08	$241.74	$197.67	60	90	149	71	107	178	28	19.0%
Energy	Off	MWH	618	1,349	1,967	$41.70	$41.70	$53.00	$53.00	26	56	82	33	71	104	22	27.1%
Fuel Cost		MWH	910	1,892	2,801	$31.10	$27.07	$30.86	$26.86	28	51	80	28	51	79	-1	-0.8%
Riders		MWH	910	1,892	2,801	$6.16	$6.16	$1.19	$1.19	6	12	17	1	2	3	-14	-80.6%
Total:										132	235	367	147	262	409	42	11.4%
A02 Res TOD OH ResSH Secondary																	
Cust Chg		Bills	167	331	498	$12.55	$12.55	$14.08	$14.08	2	4	6	2	5	7	1	12.2%
Energy	On	MWH	53	185	238	$204.97	$92.84	$241.74	$110.85	11	17	28	13	21	33	5	18.8%
Energy	Off	MWH	115	403	519	$41.70	$41.70	$53.00	$53.00	5	17	22	6	21	27	6	27.1%
Fuel Cost		MWH	168	588	757	$31.10	$27.07	$30.86	$26.86	5	16	21	5	16	21	0	-0.8%
Riders		MWH	168	588	757	$6.16	$6.16	$1.19	$1.19	1	4	5	0	1	1	-4	-80.6%
Total:										24	58	82	27	63	90	8	9.8%
A08 Res EV ResReg Secondary																	
Cust Chg		Bills	4,431	8,553	12,984	$4.95	$4.95	$5.50	$5.50	22	42	64	24	47	71	7	11.1%
Energy	On	MWH	1,454	2,602	4,056	$204.97	$165.08	$241.74	$197.67	298	430	728	352	514	866	138	19.0%
Energy	Off	MWH	18,421	32,896	51,317	$41.70	$41.70	$53.00	$53.00	768	1,372	2,140	976	1,743	2,720	580	27.1%
Fuel Cost		MWH	19,876	35,497	55,373	$31.10	$27.07	$30.86	$26.86	618	961	1,579	613	954	1,567	-12	-0.8%
Riders		MWH	19,876	35,497	55,373	$6.16	$6.16	$1.19	$1.19	122	219	341	24	42	66	-275	-80.6%
Total:										1,829	3,023	4,852	1,989	3,301	5,290	438	9.0%
A80 Res EV Pilot Bund ResReg Secondary																	
Cust Chg		Bills	696	1,344	2,040	$17.47	$17.47	$18.00	$18.00	12	23	36	13	24	37	1	3.0%
Energy	On	MWH	84	150	234	$204.97	$165.08	$241.74	$197.67	17	25	42	20	30	50	8	19.0%
Energy	Off	MWH	4,355	7,764	12,119	$41.70	$41.70	$53.00	$53.00	182	324	505	231	411	642	137	27.1%
Fuel Cost		MWH	4,439	7,913	12,352	$31.10	$27.07	$30.86	$26.86	138	214	352	137	213	350	-3	-0.8%
Riders		MWH	4,439	7,913	12,352	$6.16	$6.16	$1.19	$1.19	27	49	76	5	9	15	-61	-80.6%
Total:										376	635	1,011	406	687	1,093	82	8.1%
A81 Res EV Pilot PrePay ResReg Secondary																	
Cust Chg		Bills	332	640	972	$7.10	$7.10	$7.50	$7.50	2	5	7	2	5	7	0	5.6%
Energy	On	MWH	7	13	21	$204.97	$165.08	$241.74	$197.67	2	2	4	2	3	4	1	19.0%
Energy	Off	MWH	1,394	2,486	3,880	$41.70	$41.70	$53.00	$53.00	58	104	162	74	132	206	44	27.1%
Fuel Cost		MWH	1,402	2,499	3,901	$31.10	$27.07	$30.86	$26.86	44	68	111	43	67	110	-1	-0.8%
Riders		MWH	1,402	2,499	3,901	$6.16	$6.16	$1.19	$1.19	9	15	24	2	3	5	-19	-80.6%
Total:										114	193	308	123	209	332	25	8.0%
A04 Res TOD UG ResReg Secondary																	
Cust Chg		Bills	1,158	2,316	3,474	$12.55	$12.55	$14.08	$14.08	15	29	44	16	33	49	5	12.2%
Energy	On	MWH	358	591	948	$204.97	$165.08	$241.74	$197.67	73	97	171	86	117	203	32	19.0%
Energy	Off	MWH	720	1,425	2,145	$41.70	$41.70	$53.00	$53.00	30	59	89	38	76	114	24	27.1%
Fuel Cost		MWH	1,078	2,016	3,094	$31.10	$27.07	$30.86	$26.86	34	55	88	33	54	87	-1	-0.8%
Riders		MWH	1,078	2,016	3,094	$6.16	$6.16	$1.19	$1.19	7	12	19	1	2	4	-15	-80.6%
Total:										158	253	411	175	281	457	46	11.2%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units Summer	Billing Units Winter	Billing Units Annual	Present Rate Summer	Present Rate Winter	Proposed Rate Summer	Proposed Rate Winter	Present Revenues Summer	Present Revenues Winter	Present Revenues Annual	Proposed Revenues Summer	Proposed Revenues Winter	Proposed Revenues Annual	Increase Annual	Pct Inc. Annual
A04 Res TOD UG ResSH Secondary																
Cust Chg	Bills	162	323	485	$14.55	$14.55	$16.08	$16.08	2	5	7	3	5	8	1	10.5%
Energy On	MWH	44	153	196	$204.97	$92.84	$241.74	$110.85	9	14	23	11	17	27	4	18.8%
Energy Off	MWH	107	374	481	$41.70	$41.70	$53.00	$53.00	4	16	20	6	20	25	5	27.1%
Fuel Cost	MWH	151	526	677	$31.10	$27.07	$30.86	$26.86	5	14	19	5	14	19	0	-0.8%
Riders	MWH	151	526	677	$6.16	$6.16	$1.19	$1.19	1	3	4	0	1	1	-3	-80.6%
Total:									21	52	73	24	57	80	7	9.6%
A05 EnergyCtrl N/D ResReg Secondary																
Cust Chg	Bills	2,458	4,921	7,379	$4.95	$4.95	$5.50	$5.50	12	24	37	14	27	41	4	11.1%
Energy	MWH	1,083	5,209	6,292	$44.87	$44.87	$57.56	$57.56	49	234	282	62	300	362	80	28.3%
Opt Energy	MWH	24	106	131	$103.01	$44.87	$123.74	$57.56	3	5	7	3	6	9	2	25.5%
Fuel Cost	MWH	1,108	5,315	6,422	$31.10	$27.07	$30.86	$26.86	34	144	178	34	143	177	-1	-0.8%
Riders	MWH	1,108	5,315	6,422	$6.16	$6.16	$1.19	$1.19	7	33	40	1	6	8	-32	-80.6%
Total:									105	439	544	114	482	596	52	9.7%
A05 EnergyCtrl N/D ResSH Secondary																
Cust Chg	Bills	10,648	21,239	31,887	$4.95	$4.95	$5.50	$5.50	53	105	158	59	117	175	18	11.1%
Energy	MWH	6,916	23,643	30,559	$44.87	$44.87	$57.56	$57.56	310	1,061	1,371	398	1,361	1,759	388	28.3%
Opt Energy	MWH	760	3,163	3,923	$103.01	$44.87	$123.74	$57.56	78	142	220	94	182	276	56	25.4%
Fuel Cost	MWH	7,676	26,806	34,482	$31.10	$27.07	$30.86	$26.86	239	726	964	237	720	957	-7	-0.8%
Riders	MWH	7,676	26,806	34,482	$6.16	$6.16	$1.19	$1.19	47	165	212	9	32	41	-171	-80.6%
Total:									727	2,199	2,926	797	2,412	3,209	283	9.7%
A05 EnergyCtrl N/D Sm C&I Secondary																
Cust Chg	Bills	448	899	1,347	$4.95	$4.95	$5.50	$5.50	2	4	7	2	5	7	1	11.1%
Energy	MWH	251	1,452	1,703	$44.87	$44.87	$57.56	$57.56	11	65	76	14	84	98	22	28.3%
Opt Energy	MWH	3	106	109	$92.56	$44.87	$112.73	$57.56	0	5	5	0	6	6	1	27.9%
Fuel Cost	MWH	254	1,558	1,811	$31.49	$27.41	$32.26	$28.08	8	43	51	8	44	52	1	2.4%
Riders	MWH	254	1,558	1,811	$6.03	$6.03	$1.19	$1.19	2	9	11	0	2	2	-9	-80.2%
Total:									23	126	150	26	140	166	16	10.8%
A06 Limited Off-Peak ResReg Secondary																
Cust Chg	Bills	1,488	2,979	4,467	$4.95	$4.95	$5.50	$5.50	7	15	22	8	16	25	2	11.1%
Energy On	MWH	21	78	99	$360.00	$360.00	$408.00	$408.00	8	28	36	9	32	41	5	13.3%
Energy Off	MWH	203	2,299	2,503	$36.65	$36.65	$47.70	$47.70	7	84	92	10	110	119	28	30.2%
Fuel Cost	MWH	224	2,378	2,602	$31.10	$27.07	$30.86	$26.86	7	64	71	7	64	71	-1	-0.8%
Riders	MWH	224	2,378	2,602	$6.16	$6.16	$1.19	$1.19	1	15	16	0	3	3	-13	-80.6%
Total:									31	206	237	34	225	258	21	9.0%
A06 Limited Off-Peak ResSH Secondary																
Cust Chg	Bills	24	48	72	$4.95	$4.95	$5.50	$5.50	0	0	0	0	0	0	0	11.1%
Energy On	MWH	0	1	1	$360.00	$360.00	$408.00	$408.00	0	0	0	0	0	0	0	13.3%
Energy Off	MWH	25	88	114	$36.65	$36.65	$47.70	$47.70	1	3	4	1	4	5	1	30.2%
Fuel Cost	MWH	26	89	115	$31.10	$27.07	$30.86	$26.86	1	2	3	1	2	3	0	-0.8%
Riders	MWH	26	89	115	$6.16	$6.16	$1.19	$1.19	0	1	1	0	0	0	-1	-80.6%
Total:									2	7	9	2	7	9	1	8.5%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A06 Limited Off-Peak Sm C&I Secondary																	
Cust Chg		Bills	205	411	616	$10.00	$10.00	$11.00	$11.00	2	4	6	2	5	7	1	10.0%
Cust Chg		Bills	143	285	428	$13.60	$13.60	$15.00	$15.00	2	4	6	2	4	6	1	10.3%
Cust Chg		Bills	0	0	0	$60.00	$60.00	$60.00	$60.00	0	0	0	0	0	0	0	0.0%
Energy	On	MWH	48	91	139	$360.00	$360.00	$408.00	$408.00	17	33	50	20	37	57	7	13.3%
Energy	Off	MWH	27	616	644	$36.65	$36.65	$47.70	$47.70	1	23	24	1	29	31	7	30.2%
Energy	Off	MWH	297	731	1,028	$36.65	$36.65	$47.70	$47.70	11	27	38	14	35	49	11	30.2%
Energy	Off	MWH	0	0	0	$35.60	$35.60	$46.50	$46.50	0	0	0	0	0	0	0	0.0%
Fuel Cost		MWH	372	1,438	1,810	$31.49	$27.41	$32.26	$28.08	12	39	51	12	40	52	1	2.4%
Riders		MWH	372	1,438	1,810	$6.03	$6.03	$1.19	$1.19	2	9	11	0	2	2	-9	-80.2%
Total:										47	138	185	52	152	204	19	10.2%
A09 SmallGen UnMtrd Sm C&I Secondary																	
Cust Chg		Bills	400	800	1,200	$8.78	$8.78	$10.24	$10.24	4	7	11	4	8	12	2	16.6%
Energy		MWH	8	16	23	$92.56	$77.57	$112.73	$96.21	1	1	2	1	2	2	0	23.2%
Fuel Cost		MWH	8	16	23	$31.49	$27.41	$32.26	$28.08	0	0	1	0	0	1	0	2.4%
Riders		MWH	8	16	23	$6.03	$6.03	$1.19	$1.19	0	0	0	0	0	0	0	-80.2%
Total:										5	9	13	5	10	15	2	15.8%
A10 SmallGen Sm C&I Secondary																	
Cust Chg		Bills	300,954	601,550	902,504	$10.78	$10.78	$12.24	$12.24	3,244	6,485	9,729	3,683	7,362	11,045	1,316	13.5%
Energy		MWH	250,539	498,830	749,368	$92.56	$77.57	$112.73	$96.21	23,190	38,694	61,884	28,243	47,992	76,236	14,352	23.2%
SvrSwtchAC		Tons	146,725	0	146,725	-$5.00	$0.00	-$5.00	$0.00	-734	0	-734	-734	0	-734	0	0.0%
Fuel Cost		MWH	250,539	498,830	749,368	$31.49	$27.41	$32.26	$28.08	7,890	13,675	21,565	8,081	14,007	22,089	524	2.4%
Riders		MWH	250,539	498,830	749,368	$6.03	$6.03	$1.19	$1.19	1,511	3,009	4,521	299	595	894	-3,627	-80.2%
Total:										35,102	61,863	96,965	39,573	69,957	109,530	12,565	13.0%
A40 Small Mun Pumping Public Auth Secondary																	
Cust Chg		Bills	3,728	7,451	11,179	$10.78	$10.78	$12.24	$12.24	40	80	121	46	91	137	16	13.5%
Energy		MWH	2,241	4,819	7,060	$92.56	$77.57	$112.73	$96.21	207	374	581	253	464	716	135	23.2%
Fuel Cost		MWH	2,241	4,819	7,060	$31.49	$27.41	$32.26	$28.08	71	132	203	72	135	208	5	2.4%
Riders		MWH	2,241	4,819	7,060	$6.03	$6.03	$1.19	$1.19	14	29	43	3	6	8	-34	-80.2%
Total:										332	615	947	373	696	1,069	122	12.9%
A11 WtrHeating Sm C&I Secondary																	
Cust Chg		Bills	320	640	960	$0.00	$0.00	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Energy		MWH	68	148	216	$92.56	$77.57	$112.73	$96.21	6	12	18	8	14	22	4	23.2%
Fuel Cost		MWH	68	148	216	$31.49	$27.41	$32.26	$28.08	2	4	6	2	4	6	0	2.4%
Riders		MWH	68	148	216	$6.03	$6.03	$1.19	$1.19	0	1	1	0	0	0	-1	-80.2%
Total:										9	16	25	10	19	28	3	12.8%
A13 Direct Current Sm C&I Secondary																	
Cust Chg		Bills	12	24	36	$10.78	$10.78	$12.24	$12.24	0	0	0	0	0	0	0	13.5%
Energy		MWH	1	2	2	$92.56	$77.57	$112.73	$96.21	0	0	0	0	0	0	0	23.1%
Demand		KW	676	1,352	2,028	$3.61	$3.61	$4.00	$4.00	2	5	7	3	5	8	1	10.8%
Fuel Cost		MWH	1	2	2	$31.49	$27.41	$32.26	$28.08	0	0	0	0	0	0	0	2.4%
Riders		MWH	1	2	2	$6.03	$6.03	$1.19	$1.19	0	0	0	0	0	0	0	-80.2%
Total:										3	5	8	3	6	9	1	11.0%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A12 SmallGen TOD Sm C&I Secondary																	
Cust Chg		Bills	11,678	23,344	35,022	$12.78	$12.78	$14.24	$14.24	149	298	448	166	332	499	51	11.4%
Energy	On	MWH	3,584	9,078	12,662	$148.80	$117.23	$178.46	$143.74	533	1,064	1,598	640	1,305	1,945	347	21.7%
Energy	Off	MWH	7,343	18,772	26,115	$41.70	$41.70	$53.00	$53.00	306	783	1,089	389	995	1,384	295	27.1%
SvrSwtchAC		Tons	766	0	766	-$5.00	$0.00	-$5.00	$0.00	-4	0	-4	-4	0	-4	0	0.0%
Fuel Cost		MWH	10,927	27,850	38,777	$31.49	$27.41	$32.26	$28.08	344	763	1,108	352	782	1,135	27	2.4%
Riders		MWH	10,927	27,850	38,777	$6.03	$6.03	$1.19	$1.19	66	168	234	13	33	46	-188	-80.2%
Total:										1,395	3,077	4,472	1,557	3,447	5,004	532	11.9%
A16 SGS TOD kWh Mtr Sm C&I Secondary																	
Cust Chg		Bills	12,302	24,591	36,893	$10.78	$10.78	$12.24	$12.24	133	265	398	151	301	451	54	13.5%
Energy		MWH	4,424	9,715	14,139	$79.19	$68.14	$96.91	$84.76	350	662	1,012	429	823	1,252	240	23.7%
Fuel Cost		MWH	4,424	9,715	14,139	$31.49	$27.41	$32.26	$28.08	139	266	406	143	273	416	10	2.4%
Riders		MWH	4,424	9,715	14,139	$6.03	$6.03	$1.19	$1.19	27	59	85	5	12	17	-68	-80.2%
Total:										649	1,252	1,901	727	1,409	2,136	235	12.4%
A18 SGS TOD UnMtrd Sm C&I Secondary																	
Cust Chg		Bills	17,475	34,930	52,405	$8.78	$8.78	$10.24	$10.24	153	307	460	179	358	537	76	16.6%
Energy		MWH	8,681	17,680	26,361	$79.19	$68.14	$96.91	$84.76	687	1,205	1,892	841	1,499	2,340	448	23.7%
Fuel Cost		MWH	8,681	17,680	26,361	$31.49	$27.41	$32.26	$28.08	273	485	758	280	496	776	18	2.4%
Riders		MWH	8,681	17,680	26,361	$6.03	$6.03	$1.19	$1.19	52	107	159	10	21	31	-128	-80.2%
Total:										1,167	2,103	3,269	1,311	2,374	3,684	415	12.7%
A22 SGS TOD Low Watt Sm C&I Secondary																	
Cust Chg		Bills	2,977	5,951	8,928	$0.00	$0.00	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
LwWattSm		Bills	72,592	145,184	217,776	$0.30	$0.30	$0.33	$0.33	22	44	65	24	48	72	7	10.0%
LwWattLg		Bills	168	336	504	$1.20	$1.20	$1.30	$1.30	0	0	1	0	0	1	0	8.3%
Energy		MWH	743	1,502	2,246	$79.19	$68.14	$96.91	$84.76	59	102	161	72	127	199	38	23.7%
Fuel Cost		MWH	743	1,502	2,246	$31.49	$27.41	$32.26	$28.08	23	41	65	24	42	66	2	2.4%
Riders		MWH	743	1,502	2,246	$6.03	$6.03	$1.19	$1.19	4	9	14	1	2	3	-11	-80.2%
Total:										109	197	305	121	220	341	35	11.6%
A14 General Sm C&I Secondary																	
Cust Chg		Bills	166,781	333,367	500,148	$27.98	$27.98	$28.73	$28.73	4,667	9,328	13,994	4,792	9,579	14,371	377	2.7%
Energy		MWH	2,653,993	4,793,858	7,447,851	$34.07	$34.07	$42.11	$42.11	90,422	163,327	253,748	111,760	201,869	313,629	59,881	23.6%
Energy Cr		MWH	124,594	276,996	401,590	-$15.18	-$15.18	-$17.75	-$17.75	-1,891	-4,205	-6,096	-2,212	-4,917	-7,128	-1,032	16.9%
SvrSwtchAC		Tons	435,935	0	435,935	-$5.00	$0.00	-$5.00	$0.00	-2,180	0	-2,180	-2,180	0	-2,180	0	0.0%
Demand		KW	8,428,099	14,772,497	23,200,596	$14.79	$10.49	$17.09	$12.59	124,652	154,963	279,615	144,036	185,986	330,022	50,407	18.0%
BIS Rdr		KW	1,535	3,793	5,328	-$5.92	-$4.20	-$6.84	-$5.04	-9	-16	-25	-10	-19	-30	-5	18.4%
Fuel Cost		MWH	2,653,993	4,793,858	7,447,851	$28.01	$28.01	$28.08	$28.08	74,328	134,258	208,586	74,516	134,596	209,112	526	0.3%
Riders		KW	8,428,099	14,772,497	23,200,596	$1.02	$1.02	$0.00	$0.00	8,626	15,119	23,746	0	0	0	-23,746	-100.0%
Riders		MWH	2,653,993	4,793,858	7,447,851	$2.51	$2.51	$1.19	$1.19	6,666	12,041	18,708	3,167	5,721	8,889	-9,819	-52.5%
Total:										305,280	484,816	790,096	333,869	532,816	866,685	76,589	9.7%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
		Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A14 General Lg C&I Secondary																
Cust Chg	Bills	168	336	504	$27.98	$27.98	$28.73	$28.73	5	9	14	5	10	14	0	2.7%
Energy	MWH	47,643	88,772	136,415	$34.07	$34.07	$42.11	$42.11	1,623	3,024	4,648	2,006	3,738	5,744	1,097	23.6%
Energy Cr	MWH	4,840	9,002	13,843	-$15.18	-$15.18	-$17.75	-$17.75	-73	-137	-210	-86	-160	-246	-36	16.9%
SvrSwtchAC	Tons	293,332	0	293,332	-$5.00	$0.00	-$5.00	$0.00	-1,467	0	-1,467	-1,467	0	-1,467	0	0.0%
Demand	KW	127,707	233,618	361,326	$14.79	$10.49	$17.09	$12.59	1,889	2,451	4,339	2,183	2,941	5,124	784	18.1%
Fuel Cost	MWH	47,643	88,772	136,415	$28.01	$28.01	$28.08	$28.08	1,334	2,486	3,820	1,338	2,492	3,830	10	0.3%
Riders	KW	127,707	233,618	361,326	$1.02	$1.02	$0.00	$0.00	131	239	370	0	0	0	-370	-100.0%
Riders	MWH	47,643	88,772	136,415	$2.51	$2.51	$1.19	$1.19	120	223	343	57	106	163	-180	-52.5%
Total:									3,561	8,296	11,857	4,036	9,128	13,163	1,306	11.0%
A41 Municipal Pumping Public Auth Secondary																
Cust Chg	Bills	2,264	4,528	6,792	$27.98	$27.98	$28.73	$28.73	63	127	190	65	130	195	5	2.7%
Energy	MWH	24,433	34,485	58,918	$34.07	$34.07	$42.11	$42.11	832	1,175	2,007	1,029	1,452	2,481	474	23.6%
Energy Cr	MWH	1,925	1,898	3,823	-$15.18	-$15.18	-$17.75	-$17.75	-29	-29	-58	-34	-34	-68	-10	16.9%
Demand	KW	96,670	148,287	244,957	$14.79	$10.49	$17.09	$12.59	1,430	1,556	2,985	1,652	1,867	3,519	534	17.9%
Fuel Cost	MWH	24,433	34,485	58,918	$28.01	$28.01	$28.08	$28.08	684	966	1,650	686	968	1,654	4	0.3%
Riders	KW	96,670	148,287	244,957	$1.02	$1.02	$0.00	$0.00	99	152	251	0	0	0	-251	-100.0%
Riders	MWH	24,433	34,485	58,918	$2.51	$2.51	$1.19	$1.19	61	87	148	29	41	70	-78	-52.5%
Total:									3,141	4,032	7,173	3,427	4,425	7,852	679	9.5%
A14 General Sm C&I Primary																
Cust Chg	Bills	520	1,036	1,556	$27.98	$27.98	$28.73	$28.73	15	29	44	15	30	45	1	2.7%
Energy	MWH	38,506	71,698	110,204	$33.02	$33.02	$40.91	$40.91	1,272	2,368	3,639	1,575	2,933	4,508	869	23.9%
Energy Cr	MWH	1,498	4,519	6,017	-$15.18	-$15.18	-$17.75	-$17.75	-23	-69	-91	-27	-80	-107	-15	16.9%
SvrSwtchAC	Tons	3,108	0	3,108	-$5.00	$0.00	-$5.00	$0.00	-16	0	-16	-16	0	-16	0	0.0%
Demand	KW	122,217	207,571	329,788	$13.99	$9.69	$16.49	$11.99	1,710	2,011	3,721	2,015	2,489	4,504	783	21.0%
Fuel Cost	MWH	38,506	71,698	110,204	$28.01	$28.01	$28.08	$28.08	1,078	2,008	3,086	1,081	2,013	3,094	8	0.3%
Riders	KW	122,217	207,571	329,788	$1.02	$1.02	$0.00	$0.00	125	212	338	0	0	0	-338	-100.0%
Riders	MWH	38,506	71,698	110,204	$2.51	$2.51	$1.19	$1.19	97	180	277	46	86	132	-145	-52.5%
Total:									4,258	6,740	10,998	4,690	7,470	12,161	1,163	10.6%
A14 General Lg C&I Primary																
Cust Chg	Bills	16	32	48	$27.98	$27.98	$28.73	$28.73	0	1	1	0	1	1	0	2.7%
Energy	MWH	7,313	8,947	16,261	$33.02	$33.02	$40.91	$40.91	241	295	537	299	366	665	128	23.9%
Energy Cr	MWH	375	917	1,292	-$15.18	-$15.18	-$17.75	-$17.75	-6	-14	-20	-7	-16	-23	-3	16.9%
SvrSwtchAC	Tons	0	0	0	-$5.00	$0.00	-$5.00	$0.00	0	0	0	0	0	0	0	0.0%
Demand	KW	25,719	29,968	55,687	$13.99	$9.69	$16.49	$11.99	360	290	650	424	359	783	133	20.5%
Fuel Cost	MWH	7,313	8,947	16,261	$28.01	$28.01	$28.08	$28.08	205	251	455	205	251	457	1	0.3%
Riders	KW	25,719	29,968	55,687	$1.02	$1.02	$0.00	$0.00	26	31	57	0	0	0	-57	-100.0%
Riders	MWH	7,313	8,947	16,261	$2.51	$2.51	$1.19	$1.19	18	22	41	9	11	19	-21	-52.5%
Total:									846	877	1,722	931	972	1,903	181	10.5%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
		Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A41 Municipal Pumping Public Auth Primary																
Cust Chg	Bills	32	64	96	$27.98	$27.98	$28.73	$28.73	1	2	3	1	2	3	0	2.7%
Energy	MWH	551	899	1,450	$33.02	$33.02	$40.91	$40.91	18	30	48	23	37	59	11	23.9%
Energy Cr	MWH	3	7	10	-$15.18	-$15.18	-$17.75	-$17.75	0	0	0	0	0	0	0	16.9%
Demand	KW	2,530	4,407	6,938	$13.99	$9.69	$16.49	$11.99	35	43	78	42	53	95	16	21.1%
Fuel Cost	MWH	551	899	1,450	$28.01	$28.01	$28.08	$28.08	15	25	41	15	25	41	0	0.3%
Riders	KW	2,530	4,407	6,938	$1.02	$1.02	$0.00	$0.00	3	5	7	0	0	0	-7	-100.0%
Riders	MWH	551	899	1,450	$2.51	$2.51	$1.19	$1.19	1	2	4	1	1	2	-2	-52.5%
Total:									74	106	180	81	118	199	19	10.6%
A14 General Sm C&I Tr Transformed																
Cust Chg	Bills	4	8	12	$27.98	$27.98	$28.73	$28.73	0	0	0	0	0	0	0	2.7%
Energy	MWH	385	3,778	4,163	$31.40	$31.40	$39.16	$39.16	12	119	131	15	148	163	32	24.7%
Energy Cr	MWH	0	0	0	-$15.18	-$15.18	-$17.75	-$17.75	0	0	0	0	0	0	0	0.0%
Demand	KW	0	13,138	13,138	$13.24	$8.94	$15.29	$10.79	0	117	117	0	142	142	24	20.7%
Fuel Cost	MWH	385	3,778	4,163	$28.01	$28.01	$28.08	$28.08	11	106	117	11	106	117	0	0.3%
Riders	KW	0	13,138	13,138	$1.02	$1.02	$0.00	$0.00	0	13	13	0	0	0	-13	-100.0%
Riders	MWH	385	3,778	4,163	$2.51	$2.51	$1.19	$1.19	1	9	10	0	5	5	-5	-52.5%
Total:									24	365	389	26	401	427	38	9.8%
A14 General Lg C&I Tr Transformed																
Cust Chg	Bills	0	0	0	$27.98	$27.98	$28.73	$28.73	0	0	0	0	0	0	0	0.0%
Energy	MWH	0	0	0	$31.40	$31.40	$39.16	$39.16	0	0	0	0	0	0	0	0.0%
Energy Cr	MWH	0	0	0	-$15.18	-$15.18	-$17.75	-$17.75	0	0	0	0	0	0	0	0.0%
Demand	KW	0	0	0	$13.24	$8.94	$15.29	$10.79	0	0	0	0	0	0	0	0.0%
Fuel Cost	MWH	0	0	0	$28.01	$28.01	$28.08	$28.08	0	0	0	0	0	0	0	0.0%
Riders	KW	0	0	0	$1.02	$1.02	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Riders	MWH	0	0	0	$2.51	$2.51	$1.19	$1.19	0	0	0	0	0	0	0	0.0%
Total:									0	0	0	0	0	0	0	0.0%
A14 General Sm C&I Transmission																
Cust Chg	Bills	4	8	12	$27.98	$27.98	$28.73	$28.73	0	0	0	0	0	0	0	2.7%
Energy	MWH	23	45	68	$31.30	$31.30	$39.05	$39.05	1	1	2	1	2	3	1	24.8%
Energy Cr	MWH	0	0	0	-$15.18	-$15.18	-$17.75	-$17.75	0	0	0	0	0	0	0	0.0%
Demand	KW	219	414	633	$12.44	$8.14	$14.34	$9.84	3	3	6	3	4	7	1	18.4%
Fuel Cost	MWH	23	45	68	$28.01	$28.01	$28.08	$28.08	1	1	2	1	1	2	0	0.3%
Riders	KW	219	414	633	$1.02	$1.02	$0.00	$0.00	0	0	1	0	0	0	-1	-100.0%
Riders	MWH	23	45	68	$2.51	$2.51	$1.19	$1.19	0	0	0	0	0	0	0	-52.5%
Total:									4	7	11	5	7	12	1	8.2%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A15 General TOD Sm C&I Secondary																	
Cust Chg		Bills	17,552	35,084	52,636	$31.98	$31.98	$32.73	$32.73	561	1,122	1,683	575	1,148	1,723	40	2.4%
Energy	On	MWH	337,317	578,211	915,528	$48.55	$48.55	$59.84	$59.84	16,377	28,072	44,449	20,185	34,600	54,785	10,336	23.3%
Energy	Off	MWH	528,916	937,125	1,466,041	$23.41	$23.41	$29.19	$29.19	12,382	21,938	34,320	15,439	27,355	42,794	8,474	24.7%
Energy Cr		MWH	146,475	282,190	428,665	-$15.18	-$15.18	-$17.75	-$17.75	-2,223	-4,284	-6,507	-2,600	-5,009	-7,609	-1,102	16.9%
SvrSwtchAC		Tons	30,147	0	30,147	-$5.00	$0.00	-$5.00	$0.00	-151	0	-151	-151	0	-151	0	0.0%
Demand		KW	1,891,139	3,220,102	5,111,242	$14.79	$10.49	$17.09	$12.59	27,970	33,779	61,749	32,320	40,541	72,861	11,112	18.0%
Off Dmd		KW	51,201	113,308	164,510	$2.35	$2.35	$2.75	$2.75	120	266	387	141	312	452	66	17.0%
BIS Rdr		KW	0	0	0	-$5.92	-$4.20	-$6.84	-$5.04	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	337,317	578,211	915,528	$35.02	$35.02	$35.09	$35.09	11,814	20,252	32,066	11,837	20,290	32,126	60	0.2%
Fuel Cost	Off	MWH	528,916	937,125	1,466,041	$22.91	$22.91	$22.97	$22.97	12,116	21,466	33,582	12,147	21,522	33,669	87	0.3%
Riders		KW	1,891,139	3,220,102	5,111,242	$1.02	$1.02	$0.00	$0.00	1,936	3,296	5,231	0	0	0	-5,231	-100.0%
Riders		MWH	866,233	1,515,336	2,381,569	$2.51	$2.51	$1.19	$1.19	2,176	3,806	5,982	1,034	1,808	2,842	-3,140	-52.5%
Total:										83,077	129,714	212,791	90,926	142,567	233,493	20,702	9.7%
A15 General TOD Lg C&I Secondary																	
Cust Chg		Bills	804	1,608	2,412	$31.98	$31.98	$32.73	$32.73	26	51	77	26	53	79	2	2.4%
Energy	On	MWH	258,441	435,201	693,642	$48.55	$48.55	$59.84	$59.84	12,547	21,129	33,676	15,465	26,042	41,508	7,831	23.3%
Energy	Off	MWH	372,916	644,562	1,017,478	$23.41	$23.41	$29.19	$29.19	8,730	15,089	23,819	10,885	18,815	29,700	5,881	24.7%
Energy Cr		MWH	105,911	192,221	298,131	-$15.18	-$15.18	-$17.75	-$17.75	-1,608	-2,918	-4,526	-1,880	-3,412	-5,292	-766	16.9%
SvrSwtchAC		Tons	76,974	0	76,974	-$5.00	$0.00	-$5.00	$0.00	-385	0	-385	-385	0	-385	0	0.0%
Demand		KW	1,372,315	2,286,807	3,659,121	$14.79	$10.49	$17.09	$12.59	20,297	23,989	44,285	23,453	28,791	52,244	7,959	18.0%
Off Dmd		KW	16,221	48,650	64,870	$2.35	$2.35	$2.75	$2.75	38	114	152	45	134	178	26	17.0%
BIS Rdr		KW	14,631	30,240	44,871	-$5.92	-$4.20	-$6.84	-$5.04	-87	-127	-213	-100	-152	-252	-39	18.2%
AreaDevRdr		KW	0	0	0	-$2.96	-$2.10	-$3.42	-$2.52	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	258,441	435,201	693,642	$35.02	$35.02	$35.09	$35.09	9,052	15,243	24,295	9,069	15,271	24,340	46	0.2%
Fuel Cost	Off	MWH	372,916	644,562	1,017,478	$22.91	$22.91	$22.97	$22.97	8,542	14,765	23,307	8,564	14,803	23,367	60	0.3%
Riders		KW	1,372,315	2,286,807	3,659,121	$1.02	$1.02	$0.00	$0.00	1,405	2,341	3,745	0	0	0	-3,745	-100.0%
Riders		MWH	631,357	1,079,764	1,711,121	$2.51	$2.51	$1.19	$1.19	1,586	2,712	4,298	753	1,289	2,042	-2,256	-52.5%
Total:										60,143	92,388	152,531	65,896	101,633	167,529	14,999	9.8%
A15 General TOD Sm C&I Primary																	
Cust Chg		Bills	304	608	912	$31.98	$31.98	$32.73	$32.73	10	19	29	10	20	30	1	2.4%
Energy	On	MWH	21,237	33,570	54,807	$47.50	$47.50	$58.64	$58.64	1,009	1,595	2,603	1,245	1,969	3,214	610	23.4%
Energy	Off	MWH	32,578	53,005	85,583	$22.36	$22.36	$27.99	$27.99	728	1,185	1,914	912	1,484	2,395	482	25.2%
Energy Cr		MWH	9,613	14,173	23,786	-$15.18	-$15.18	-$17.75	-$17.75	-146	-215	-361	-171	-252	-422	-61	16.9%
SvrSwtchAC		Tons	2,643	0	2,643	-$5.00	$0.00	-$5.00	$0.00	-13	0	-13	-13	0	-13	0	0.0%
Demand		KW	123,252	200,631	323,883	$13.99	$9.69	$16.49	$11.99	1,724	1,944	3,668	2,032	2,406	4,438	770	21.0%
Off Dmd		KW	9,022	12,634	21,656	$1.55	$1.55	$2.15	$2.15	14	20	34	19	27	47	13	38.7%
BIS Rdr		KW	0	0	0	-$5.60	-$3.88	-$6.60	-$4.80	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	21,237	33,570	54,807	$35.02	$35.02	$35.09	$35.09	744	1,176	1,920	745	1,178	1,923	4	0.2%
Fuel Cost	Off	MWH	32,578	53,005	85,583	$22.91	$22.91	$22.97	$22.97	746	1,214	1,960	748	1,217	1,965	5	0.3%
Riders		KW	123,252	200,631	323,883	$1.02	$1.02	$0.00	$0.00	126	205	331	0	0	0	-331	-100.0%
Riders		MWH	53,815	86,575	140,391	$2.51	$2.51	$1.19	$1.19	135	217	353	64	103	168	-185	-52.5%
Total:										5,078	7,361	12,438	5,593	8,152	13,744	1,306	10.5%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A15 General TOD Lg C&I Primary																	
Cust Chg		Bills	408	816	1,224	$31.98	$31.98	$32.73	$32.73	13	26	39	13	27	40	1	2.4%
Energy		MWH	296,220	471,166	767,386	$47.50	$47.50	$58.64	$58.64	14,071	22,381	36,452	17,370	27,629	44,999	8,547	23.4%
Energy	On	MWH	454,756	749,594	1,204,350	$22.36	$22.36	$27.99	$27.99	10,169	16,762	26,930	12,728	20,980	33,709	6,778	25.2%
Energy Cr	Off	MWH	150,189	266,605	416,794	-$15.18	-$15.18	-$17.75	-$17.75	-2,280	-4,047	-6,327	-2,666	-4,732	-7,398	-1,071	16.9%
SvrSwtchAC		Tons	2,724	0	2,724	-$5.00	$0.00	-$5.00	$0.00	-14	0	-14	-14	0	-14	0	0.0%
Demand		KW	1,547,412	2,472,490	4,019,902	$13.99	$9.69	$16.49	$11.99	21,648	23,958	45,607	25,517	29,645	55,162	9,555	21.0%
Off Dmd		KW	29,933	90,047	119,980	$1.55	$1.55	$2.15	$2.15	46	140	186	64	194	258	72	38.7%
BIS Rdr		KW	9,200	19,889	29,089	-$5.60	-$3.88	-$6.60	-$4.80	-51	-77	-129	-61	-95	-156	-27	21.4%
Fuel Cost	On	MWH	296,220	471,166	767,386	$35.02	$35.02	$35.09	$35.09	10,375	16,502	26,877	10,395	16,533	26,928	51	0.2%
Fuel Cost	Off	MWH	454,756	749,594	1,204,350	$22.91	$22.91	$22.97	$22.97	10,417	17,171	27,587	10,444	17,215	27,659	71	0.3%
Riders		KW	1,547,412	2,472,490	4,019,902	$1.02	$1.02	$0.00	$0.00	1,584	2,531	4,114	0	0	0	-4,114	-100.0%
Riders		MWH	750,976	1,220,760	1,971,735	$2.51	$2.51	$1.19	$1.19	1,886	3,066	4,953	896	1,457	2,353	-2,600	-52.5%
Total:										67,864	98,412	166,277	74,687	108,852	183,539	17,263	10.4%
A29 Light Rail Sm C&I Primary																	
Cust Chg		Bills	64	128	192	$102.34	$102.34	$101.73	$101.73	7	13	20	7	13	20	0	-0.6%
Energy	On	MWH	3,180	7,086	10,266	$47.50	$47.50	$58.64	$58.64	151	337	488	186	416	602	114	23.4%
Energy	Off	MWH	3,823	9,729	13,552	$22.36	$22.36	$27.99	$27.99	85	218	303	107	272	379	76	25.2%
Energy Cr		MWH	1,286	2,835	4,122	-$13.03	-$13.03	-$15.20	-$15.20	-17	-37	-54	-20	-43	-63	-9	16.7%
Demand		KW	14,553	35,865	50,419	$8.71	$4.41	$9.40	$4.90	127	158	285	137	176	313	28	9.7%
Trans Dmd		KW	20,543	49,234	69,778	$5.28	$5.28	$7.09	$7.09	108	260	368	146	349	495	126	34.3%
Off Dmd		KW	1,336	2,518	3,855	$1.55	$1.55	$2.15	$2.15	2	4	6	3	5	8	2	38.7%
Fuel Cost	On	MWH	3,180	7,086	10,266	$35.02	$35.02	$35.09	$35.09	111	248	360	112	249	360	1	0.2%
Fuel Cost	Off	MWH	3,823	9,729	13,552	$22.91	$22.91	$22.97	$22.97	88	223	310	88	223	311	1	0.3%
Riders		KW	20,543	49,234	69,778	$1.02	$1.02	$0.00	$0.00	21	50	71	0	0	0	-71	-100.0%
Riders		MWH	7,003	16,815	23,818	$2.51	$2.51	$1.19	$1.19	18	42	60	8	20	28	-31	-52.5%
Total:										701	1,516	2,217	773	1,680	2,454	236	10.7%
A15 General TOD Sm C&I Transmission																	
Cust Chg		Bills	4	8	12	$31.98	$31.98	$32.73	$32.73	0	0	0	0	0	0	0	2.4%
Energy	On	MWH	38	77	115	$45.78	$45.78	$56.78	$56.78	2	4	5	2	4	7	1	24.0%
Energy	Off	MWH	0	0	0	$20.64	$20.64	$26.13	$26.13	0	0	0	0	0	0	0	0.0%
Energy Cr		MWH	10	14	24	-$15.18	-$15.18	-$17.75	-$17.75	0	0	0	0	0	0	0	16.9%
SvrSwtchAC		Tons	0	0	0	-$5.00	$0.00	-$5.00	$0.00	0	0	0	0	0	0	0	0.0%
Demand		KW	206	895	1,101	$12.44	$8.14	$14.34	$9.84	3	7	10	3	9	12	2	19.4%
Off Dmd		KW	0	0	0	$0.00	$0.00	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	38	77	115	$35.02	$35.02	$35.09	$35.09	1	3	4	1	3	4	0	0.2%
Fuel Cost	Off	MWH	0	0	0	$22.91	$22.91	$22.97	$22.97	0	0	0	0	0	0	0	0.0%
Riders		KW	206	895	1,101	$1.02	$1.02	$0.00	$0.00	0	1	1	0	0	0	-1	-100.0%
Riders		MWH	38	77	115	$2.51	$2.51	$1.19	$1.19	0	0	0	0	0	0	0	-52.5%
Total:										6	15	21	6	16	22	2	9.0%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A15 General TOD Lg C&I Tr Transformed																	
Cust Chg		Bills	24	48	72	$31.98	$31.98	$32.73	$32.73	1	2	2	1	2	2	0	2.4%
Energy	On	MWH	157,042	252,660	409,702	$45.88	$45.88	$56.89	$56.89	7,205	11,592	18,797	8,934	14,373	23,307	4,510	24.0%
Energy	Off	MWH	263,257	444,014	707,271	$20.74	$20.74	$26.24	$26.24	5,460	9,209	14,669	6,907	11,650	18,557	3,888	26.5%
Energy Cr		MWH	159,317	269,197	428,513	-$15.18	-$15.18	-$17.75	-$17.75	-2,418	-4,086	-6,505	-2,828	-4,778	-7,606	-1,101	16.9%
SvrSwtchAC		Tons	752	0	752	-$5.00	$0.00	-$5.00	$0.00	-4	0	-4	-4	0	-4	0	0.0%
Demand		KW	682,800	1,095,063	1,777,862	$13.24	$8.94	$15.29	$10.79	9,040	9,790	18,830	10,440	11,816	22,256	3,426	18.2%
Off Dmd		KW	1,082	8,551	9,632	$0.80	$0.80	$0.95	$0.95	1	7	8	1	8	9	1	18.8%
Fuel Cost	On	MWH	157,042	252,660	409,702	$35.02	$35.02	$35.09	$35.09	5,500	8,849	14,350	5,511	8,866	14,377	27	0.2%
Fuel Cost	Off	MWH	263,257	444,014	707,271	$22.91	$22.91	$22.97	$22.97	6,030	10,171	16,201	6,046	10,197	16,243	42	0.3%
Riders		KW	682,800	1,095,063	1,777,862	$1.02	$1.02	$0.00	$0.00	699	1,121	1,820	0	0	0	-1,820	-100.0%
Riders		MWH	420,299	696,674	1,116,973	$2.51	$2.51	$1.19	$1.19	1,056	1,750	2,806	502	831	1,333	-1,473	-52.5%
Total:										32,570	48,404	80,973	35,509	52,964	88,474	7,500	9.3%
A15 General TOD Lg C&I Transmission																	
Cust Chg		Bills	12	24	36	$31.98	$31.98	$32.73	$32.73	0	1	1	0	1	1	0	2.4%
Energy	On	MWH	7,593	17,217	24,809	$45.78	$45.78	$56.78	$56.78	348	788	1,136	431	978	1,409	273	24.0%
Energy	Off	MWH	13,022	27,240	40,262	$20.64	$20.64	$26.13	$26.13	269	562	831	340	712	1,052	221	26.6%
Energy Cr		MWH	0	336	336	-$15.18	-$15.18	-$17.75	-$17.75	0	-5	-5	0	-6	-6	-1	16.9%
Demand		KW	61,119	113,908	175,027	$12.44	$8.14	$14.34	$9.84	760	927	1,688	876	1,121	1,997	310	18.4%
Off Dmd		KW	0	0	0	$0.00	$0.00	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	7,593	17,217	24,809	$35.02	$35.02	$35.09	$35.09	266	603	869	266	604	871	2	0.2%
Fuel Cost	Off	MWH	13,022	27,240	40,262	$22.91	$22.91	$22.97	$22.97	298	624	922	299	626	925	2	0.3%
Riders		KW	61,119	113,908	175,027	$1.02	$1.02	$0.00	$0.00	63	117	179	0	0	0	-179	-100.0%
Riders		MWH	20,615	44,456	65,071	$2.51	$2.51	$1.19	$1.19	52	112	163	25	53	78	-86	-52.5%
Total:										2,056	3,729	5,784	2,238	4,088	6,326	542	9.4%
A23 Peak-Ctrl Tier Sm C&I Secondary																	
Cust Chg		Bills	5,468	10,931	16,399	$57.34	$57.34	$61.73	$61.73	314	627	940	338	675	1,012	72	7.7%
Energy		MWH	342,583	651,165	993,748	$34.07	$34.07	$42.11	$42.11	11,672	22,185	33,857	14,426	27,421	41,847	7,990	23.6%
Energy Cr		MWH	11,537	22,237	33,773	-$15.18	-$15.18	-$17.75	-$17.75	-175	-338	-513	-205	-395	-599	-87	16.9%
Demand		KW	511,641	997,612	1,509,253	$14.79	$10.49	$17.09	$12.59	7,567	10,465	18,032	8,744	12,560	21,304	3,272	18.1%
Control Dmd		KW	321,520	503,374	824,894	$8.88	$8.88	$10.98	$10.98	2,855	4,470	7,325	3,530	5,527	9,057	1,732	23.6%
Control Dmd		KW	217,535	336,281	553,816	$7.86	$7.86	$9.83	$9.83	1,710	2,643	4,353	2,138	3,306	5,444	1,091	25.1%
Control Dmd		KW	180,242	313,010	493,252	$7.34	$7.34	$9.29	$9.29	1,323	2,297	3,620	1,674	2,908	4,582	962	26.6%
Control Dmd		KW	10,967	19,508	30,475	$7.15	$7.15	$9.09	$9.09	78	139	218	100	177	277	59	27.1%
Control Dmd		KW	42,115	76,974	119,089	$6.56	$6.56	$8.47	$8.47	276	505	781	357	652	1,009	227	29.1%
Control Dmd		KW	2,572	5,868	8,440	$6.09	$6.09	$7.97	$7.97	16	36	51	21	47	67	16	30.9%
AnnMinDmd		KW	39,935	79,870	119,805	$1.00	$1.00	$1.27	$1.27	40	80	120	51	101	152	32	27.0%
Fuel Cost		MWH	342,583	651,165	993,748	$28.01	$28.01	$28.08	$28.08	9,594	18,237	27,831	9,619	18,283	27,901	70	0.3%
Riders		KW	1,286,592	2,252,627	3,539,219	$1.02	$1.02	$0.00	$0.00	1,317	2,306	3,622	0	0	0	-3,622	-100.0%
Riders		MWH	342,583	651,165	993,748	$2.51	$2.51	$1.19	$1.19	861	1,636	2,496	409	777	1,186	-1,310	-52.5%
Total:										37,447	65,288	102,735	41,201	72,038	113,240	10,504	10.2%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
		Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A23 Peak-Ctrl Tier Lg C&I Secondary																
Cust Chg	Bills	16	32	48	$57.34	$57.34	$61.73	$61.73	1	2	3	1	2	3	0	7.7%
Energy	MWH	5,240	8,765	14,004	$34.07	$34.07	$42.11	$42.11	179	299	477	221	369	590	113	23.6%
Energy Cr	MWH	470	875	1,344	-$15.18	-$15.18	-$17.75	-$17.75	-7	-13	-20	-8	-16	-24	-3	16.9%
Demand	KW	2,962	4,562	7,524	$14.79	$10.49	$17.09	$12.59	44	48	92	51	57	108	16	17.9%
Control Dmd	KW	3,374	4,513	7,888	$8.88	$8.88	$10.98	$10.98	30	40	70	37	50	87	17	23.6%
Control Dmd	KW	3,305	4,168	7,473	$7.86	$7.86	$9.83	$9.83	26	33	59	32	41	73	15	25.1%
Control Dmd	KW	6,513	10,569	17,082	$7.34	$7.34	$9.29	$9.29	48	78	125	61	98	159	33	26.6%
Control Dmd	KW	0	0	0	$7.15	$7.15	$9.09	$9.09	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	672	1,095	1,767	$6.56	$6.56	$8.47	$8.47	4	7	12	6	9	15	3	29.1%
Control Dmd	KW	0	0	0	$6.09	$6.09	$7.97	$7.97	0	0	0	0	0	0	0	0.0%
Fuel Cost	MWH	5,240	8,765	14,004	$28.01	$28.01	$28.08	$28.08	147	245	392	147	246	393	1	0.3%
Riders	KW	16,826	24,908	41,734	$1.02	$1.02	$0.00	$0.00	17	25	43	0	0	0	-43	-100.0%
Riders	MWH	5,240	8,765	14,004	$2.51	$2.51	$1.19	$1.19	13	22	35	6	10	17	-18	-52.5%
Total:									501	786	1,287	553	868	1,421	134	10.4%
A23 Peak-Ctrl Tier Sm C&I Primary																
Cust Chg	Bills	184	365	549	$57.34	$57.34	$61.73	$61.73	11	21	31	11	23	34	2	7.7%
Energy	MWH	22,030	45,589	67,618	$33.02	$33.02	$40.91	$40.91	727	1,505	2,233	901	1,865	2,766	533	23.9%
Energy Cr	MWH	513	1,615	2,128	-$15.18	-$15.18	-$17.75	-$17.75	-8	-25	-32	-9	-29	-38	-5	16.9%
Demand	KW	28,243	58,807	87,049	$13.99	$9.69	$16.49	$11.99	395	570	965	466	705	1,171	206	21.3%
Control Dmd	KW	25,705	44,127	69,833	$8.08	$8.08	$10.38	$10.38	208	357	564	267	458	725	161	28.5%
Control Dmd	KW	9,243	17,405	26,648	$7.06	$7.06	$9.23	$9.23	65	123	188	85	161	246	58	30.7%
Control Dmd	KW	13,530	16,305	29,835	$6.54	$6.54	$8.69	$8.69	88	107	195	118	142	259	64	32.9%
Control Dmd	KW	3,065	5,725	8,790	$6.35	$6.35	$8.49	$8.49	19	36	56	26	49	75	19	33.7%
Control Dmd	KW	1,988	5,667	7,655	$5.76	$5.76	$7.87	$7.87	11	33	44	16	45	60	16	36.6%
Control Dmd	KW	2,929	5,600	8,529	$5.29	$5.29	$7.37	$7.37	15	30	45	22	41	63	18	39.3%
Fuel Cost	MWH	22,030	45,589	67,618	$28.01	$28.01	$28.08	$28.08	617	1,277	1,894	619	1,280	1,899	5	0.3%
Riders	KW	84,702	153,636	238,338	$1.02	$1.02	$0.00	$0.00	87	157	244	0	0	0	-244	-100.0%
Riders	MWH	22,030	45,589	67,618	$2.51	$2.51	$1.19	$1.19	55	115	170	26	54	81	-89	-52.5%
Total:									2,292	4,305	6,597	2,547	4,793	7,340	743	11.3%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
		Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A23 Peak-Ctrl Tier Lg C&I Primary																
Cust Chg	Bills	0	0	0	$57.34	$57.34	$61.73	$61.73	0	0	0	0	0	0	0	0.0%
Energy	MWH	0	0	0	$33.02	$33.02	$40.91	$40.91	0	0	0	0	0	0	0	0.0%
Energy Cr	MWH	0	0	0	-$15.18	-$15.18	-$17.75	-$17.75	0	0	0	0	0	0	0	0.0%
Demand	KW	0	0	0	$13.99	$9.69	$16.49	$11.99	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$8.08	$8.08	$10.38	$10.38	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$7.06	$7.06	$9.23	$9.23	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$6.54	$6.54	$8.69	$8.69	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$6.35	$6.35	$8.49	$8.49	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$5.76	$5.76	$7.87	$7.87	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$5.29	$5.29	$7.37	$7.37	0	0	0	0	0	0	0	0.0%
Fuel Cost	MWH	0	0	0	$28.01	$28.01	$28.08	$28.08	0	0	0	0	0	0	0	0.0%
Riders	KW	0	0	0	$1.02	$1.02	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Riders	MWH	0	0	0	$2.51	$2.51	$1.19	$1.19	0	0	0	0	0	0	0	0.0%
Total:									0	0	0	0	0	0	0	0.0%
A23 Peak-Ctrl Tier Sm C&I Tr Transformed																
Cust Chg	Bills	0	0	0	$57.34	$57.34	$61.73	$61.73	0	0	0	0	0	0	0	0.0%
Energy	MWH	0	0	0	$31.40	$31.40	$39.16	$39.16	0	0	0	0	0	0	0	0.0%
Energy Cr	MWH	0	0	0	-$15.18	-$15.18	-$17.75	-$17.75	0	0	0	0	0	0	0	0.0%
Demand	KW	0	0	0	$13.24	$8.94	$15.29	$10.79	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$7.33	$7.33	$9.18	$9.18	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$6.31	$6.31	$8.03	$8.03	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$5.79	$5.79	$7.49	$7.49	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$5.60	$5.60	$7.29	$7.29	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$5.01	$5.01	$6.67	$6.67	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$4.54	$4.54	$6.17	$6.17	0	0	0	0	0	0	0	0.0%
Fuel Cost	MWH	0	0	0	$28.01	$28.01	$28.08	$28.08	0	0	0	0	0	0	0	0.0%
Riders	KW	0	0	0	$1.02	$1.02	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Riders	MWH	0	0	0	$2.51	$2.51	$1.19	$1.19	0	0	0	0	0	0	0	0.0%
Total:									0	0	0	0	0	0	0	0.0%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
		Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A23 Peak-Ctrl Tier Sm C&I Transmission																
Cust Chg	Bills	8	16	24	$57.34	$57.34	$61.73	$61.73	0	1	1	0	1	1	0	7.7%
Energy	MWH	1,105	2,252	3,357	$31.30	$31.30	$39.05	$39.05	35	70	105	43	88	131	26	24.8%
Energy Cr	MWH	0	0	0	-$15.18	-$15.18	-$17.75	-$17.75	0	0	0	0	0	0	0	0.0%
Demand	KW	201	415	615	$12.44	$8.14	$14.34	$9.84	2	3	6	3	4	7	1	18.5%
Control Dmd	KW	973	1,534	2,507	$6.53	$6.53	$8.23	$8.23	6	10	16	8	13	21	4	26.0%
Control Dmd	KW	0	0	0	$5.51	$5.51	$7.08	$7.08	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	2,888	6,174	9,062	$4.99	$4.99	$6.54	$6.54	14	31	45	19	40	59	14	31.1%
Control Dmd	KW	0	0	0	$4.80	$4.80	$6.34	$6.34	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$4.21	$4.21	$5.72	$5.72	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$3.74	$3.74	$5.22	$5.22	0	0	0	0	0	0	0	0.0%
Fuel Cost	MWH	1,105	2,252	3,357	$28.01	$28.01	$28.08	$28.08	31	63	94	31	63	94	0	0.3%
Riders	KW	4,062	8,123	12,184	$1.02	$1.02	$0.00	$0.00	4	8	12	0	0	0	-12	-100.0%
Riders	MWH	1,105	2,252	3,357	$2.51	$2.51	$1.19	$1.19	3	6	8	1	3	4	-4	-52.5%
Total:									96	193	289	106	212	318	29	10.0%
A23 Peak-Ctrl Tier Lg C&I Transmission																
Cust Chg	Bills	4	8	12	$57.34	$57.34	$61.73	$61.73	0	0	1	0	0	1	0	7.7%
Energy	MWH	1,312	2,646	3,958	$31.30	$31.30	$39.05	$39.05	41	83	124	51	103	155	31	24.8%
Energy Cr	MWH	0	0	0	-$15.18	-$15.18	-$17.75	-$17.75	0	0	0	0	0	0	0	0.0%
Demand	KW	122	256	378	$12.44	$8.14	$14.34	$9.84	2	2	4	2	3	4	1	18.5%
Control Dmd	KW	0	0	0	$6.53	$6.53	$8.23	$8.23	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$5.51	$5.51	$7.08	$7.08	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	4,030	7,820	11,850	$4.99	$4.99	$6.54	$6.54	20	39	59	26	51	77	18	31.1%
Control Dmd	KW	0	0	0	$4.80	$4.80	$6.34	$6.34	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$4.21	$4.21	$5.72	$5.72	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$3.74	$3.74	$5.22	$5.22	0	0	0	0	0	0	0	0.0%
Fuel Cost	MWH	1,312	2,646	3,958	$28.01	$28.01	$28.08	$28.08	37	74	111	37	74	111	0	0.3%
Riders	KW	4,151	8,076	12,228	$1.02	$1.02	$0.00	$0.00	4	8	13	0	0	0	-13	-100.0%
Riders	MWH	1,312	2,646	3,958	$2.51	$2.51	$1.19	$1.19	3	7	10	2	3	5	-5	-52.5%
Total:									107	213	321	118	235	353	32	10.1%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A24 Peak-Ctrl Tier TOD Sm C&I Secondary																	
Cust Chg		Bills	781	1,563	2,344	$57.34	$57.34	$61.73	$61.73	45	90	134	48	96	145	10	7.7%
Energy	On	MWH	57,761	103,445	161,206	$48.55	$48.55	$59.84	$59.84	2,804	5,022	7,827	3,456	6,190	9,647	1,820	23.3%
Energy	Off	MWH	89,729	163,435	253,164	$23.41	$23.41	$29.19	$29.19	2,101	3,826	5,927	2,619	4,771	7,390	1,463	24.7%
Energy Cr		MWH	24,848	46,445	71,293	-$15.18	-$15.18	-$17.75	-$17.75	-377	-705	-1,082	-441	-824	-1,265	-183	16.9%
Demand		KW	106,614	195,854	302,468	$14.79	$10.49	$17.09	$12.59	1,577	2,055	3,631	1,822	2,466	4,288	657	18.1%
Off Dmd		KW	8,014	25,608	33,621	$2.35	$2.35	$2.75	$2.75	19	60	79	22	70	92	13	17.0%
Control Dmd		KW	51,622	83,535	135,157	$8.88	$8.88	$10.98	$10.98	458	742	1,200	567	917	1,484	284	23.6%
Control Dmd		KW	40,429	71,605	112,035	$7.86	$7.86	$9.83	$9.83	318	563	881	397	704	1,101	221	25.1%
Control Dmd		KW	119,134	207,090	326,223	$7.34	$7.34	$9.29	$9.29	874	1,520	2,394	1,107	1,924	3,031	636	26.6%
Control Dmd		KW	3,831	7,277	11,108	$7.15	$7.15	$9.09	$9.09	27	52	79	35	66	101	22	27.1%
Control Dmd		KW	11,113	20,161	31,275	$6.56	$6.56	$8.47	$8.47	73	132	205	94	171	265	60	29.1%
Control Dmd		KW	0	0	0	$6.09	$6.09	$7.97	$7.97	0	0	0	0	0	0	0	0.0%
AnnMinDmd		KW	1,052	2,104	3,156	$1.00	$1.00	$1.27	$1.27	1	2	3	1	3	4	1	27.0%
Fuel Cost	On	MWH	57,761	103,445	161,206	$35.02	$35.02	$35.09	$35.09	2,023	3,623	5,646	2,027	3,630	5,657	11	0.2%
Fuel Cost	Off	MWH	89,729	163,435	253,164	$22.91	$22.91	$22.97	$22.97	2,055	3,744	5,799	2,061	3,753	5,814	15	0.3%
Riders		KW	332,744	585,522	918,265	$1.02	$1.02	$0.00	$0.00	341	599	940	0	0	0	-940	-100.0%
Riders		MWH	147,490	266,880	414,370	$2.51	$2.51	$1.19	$1.19	370	670	1,041	176	319	495	-546	-52.5%
Total:										12,710	21,995	34,705	13,992	24,256	38,247	3,543	10.2%
A24 Peak-Ctrl Tier TOD Lg C&I Secondary																	
Cust Chg		Bills	204	408	612	$57.34	$57.34	$61.73	$61.73	12	23	35	13	25	38	3	7.7%
Energy	On	MWH	57,490	102,936	160,426	$48.55	$48.55	$59.84	$59.84	2,791	4,998	7,789	3,440	6,160	9,600	1,811	23.3%
Energy	Off	MWH	86,060	153,641	239,701	$23.41	$23.41	$29.19	$29.19	2,015	3,597	5,611	2,512	4,485	6,997	1,385	24.7%
Energy Cr		MWH	23,160	40,164	63,324	-$15.18	-$15.18	-$17.75	-$17.75	-352	-610	-961	-411	-713	-1,124	-163	16.9%
Demand		KW	114,166	210,410	324,576	$14.79	$10.49	$17.09	$12.59	1,689	2,207	3,896	1,951	2,649	4,600	704	18.1%
Off Dmd		KW	4,279	7,651	11,930	$2.35	$2.35	$2.75	$2.75	10	18	28	12	21	33	5	17.0%
Control Dmd		KW	47,766	93,191	140,958	$8.88	$8.88	$10.98	$10.98	424	828	1,252	524	1,023	1,548	296	23.6%
Control Dmd		KW	23,258	44,995	68,252	$7.86	$7.86	$9.83	$9.83	183	354	536	229	442	671	134	25.1%
Control Dmd		KW	116,524	199,695	316,220	$7.34	$7.34	$9.29	$9.29	855	1,466	2,321	1,083	1,855	2,938	617	26.6%
Control Dmd		KW	5,406	9,907	15,313	$7.15	$7.15	$9.09	$9.09	39	71	109	49	90	139	30	27.1%
Control Dmd		KW	32,169	57,917	90,085	$6.56	$6.56	$8.47	$8.47	211	380	591	272	491	763	172	29.1%
Control Dmd		KW	0	0	0	$6.09	$6.09	$7.97	$7.97	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	57,490	102,936	160,426	$35.02	$35.02	$35.09	$35.09	2,014	3,605	5,619	2,017	3,612	5,629	11	0.2%
Fuel Cost	Off	MWH	86,060	153,641	239,701	$22.91	$22.91	$22.97	$22.97	1,971	3,519	5,491	1,976	3,528	5,505	14	0.3%
Riders		KW	339,290	616,115	955,404	$1.02	$1.02	$0.00	$0.00	347	631	978	0	0	0	-978	-100.0%
Riders		MWH	143,550	256,577	400,127	$2.51	$2.51	$1.19	$1.19	361	644	1,005	171	306	478	-528	-52.5%
Total:										12,569	21,731	34,300	13,839	23,975	37,814	3,514	10.2%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A24 Peak-Ctrl Tier TOD Sm C&I Primary																	
Cust Chg		Bills	68	136	204	$57.34	$57.34	$61.73	$61.73	4	8	12	4	8	13	1	7.7%
Energy	On	MWH	8,962	15,327	24,290	$47.50	$47.50	$58.64	$58.64	426	728	1,154	526	899	1,424	271	23.4%
Energy	Off	MWH	15,116	25,282	40,399	$22.36	$22.36	$27.99	$27.99	338	565	903	423	708	1,131	227	25.2%
Energy Cr		MWH	4,705	8,534	13,238	-$15.18	-$15.18	-$17.75	-$17.75	-71	-130	-201	-84	-151	-235	-34	16.9%
Demand		KW	18,742	31,046	49,788	$13.99	$9.69	$16.49	$11.99	262	301	563	309	372	681	118	21.0%
Off Dmd		KW	2,837	5,500	8,336	$1.55	$1.55	$2.15	$2.15	4	9	13	6	12	18	5	38.7%
Control Dmd		KW	7,087	15,314	22,400	$8.08	$8.08	$10.38	$10.38	57	124	181	74	159	233	52	28.5%
Control Dmd		KW	4,544	5,239	9,782	$7.06	$7.06	$9.23	$9.23	32	37	69	42	48	90	21	30.7%
Control Dmd		KW	16,436	26,631	43,067	$6.54	$6.54	$8.69	$8.69	107	174	282	143	231	374	93	32.9%
Control Dmd		KW	0	0	0	$6.35	$6.35	$8.49	$8.49	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	5,093	8,120	13,214	$5.76	$5.76	$7.87	$7.87	29	47	76	40	64	104	28	36.6%
Control Dmd		KW	0	0	0	$5.29	$5.29	$7.37	$7.37	0	0	0	0	0	0	0	0.0%
AnnMinDmdChg		KW	0	0	0	$1.00	$1.00	$1.27	$1.27	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	8,962	15,327	24,290	$35.02	$35.02	$35.09	$35.09	314	537	851	314	538	852	2	0.2%
Fuel Cost	Off	MWH	15,116	25,282	40,399	$22.91	$22.91	$22.97	$22.97	346	579	925	347	581	928	2	0.3%
Riders		KW	51,902	86,349	138,251	$1.02	$1.02	$0.00	$0.00	53	88	141	0	0	0	-141	-100.0%
Riders		MWH	24,079	40,610	64,688	$2.51	$2.51	$1.19	$1.19	60	102	162	29	48	77	-85	-52.5%
Total:										1,963	3,169	5,132	2,173	3,517	5,690	558	10.9%
A24 Peak-Ctrl Tier TOD Lg C&I Primary																	
Cust Chg		Bills	296	592	888	$57.34	$57.34	$61.73	$61.73	17	34	51	18	37	55	4	7.7%
Energy	On	MWH	170,406	297,845	468,251	$47.50	$47.50	$58.64	$58.64	8,094	14,148	22,242	9,992	17,465	27,458	5,215	23.4%
Energy	Off	MWH	264,030	465,398	729,428	$22.36	$22.36	$27.99	$27.99	5,904	10,407	16,311	7,390	13,026	20,416	4,105	25.2%
Energy Cr		MWH	74,812	148,937	223,749	-$15.18	-$15.18	-$17.75	-$17.75	-1,136	-2,261	-3,397	-1,328	-2,644	-3,972	-575	16.9%
Demand		KW	403,668	706,840	1,110,508	$13.99	$9.69	$16.49	$11.99	5,647	6,849	12,497	6,656	8,475	15,131	2,635	21.1%
Off Dmd		KW	12,398	25,934	38,333	$1.55	$1.55	$2.15	$2.15	19	40	59	27	56	82	23	38.7%
Control Dmd		KW	36,605	60,439	97,044	$8.08	$8.08	$10.38	$10.38	296	488	784	380	627	1,007	223	28.5%
Control Dmd		KW	81,700	137,063	218,763	$7.06	$7.06	$9.23	$9.23	577	968	1,544	754	1,265	2,019	475	30.7%
Control Dmd		KW	267,289	444,083	711,372	$6.54	$6.54	$8.69	$8.69	1,748	2,904	4,652	2,323	3,859	6,182	1,529	32.9%
Control Dmd		KW	38,941	59,039	97,980	$6.35	$6.35	$8.49	$8.49	247	375	622	331	501	832	210	33.7%
Control Dmd		KW	87,447	150,534	237,981	$5.76	$5.76	$7.87	$7.87	504	867	1,371	688	1,185	1,873	502	36.6%
Control Dmd		KW	49,494	101,148	150,642	$5.29	$5.29	$7.37	$7.37	262	535	797	365	745	1,110	313	39.3%
BIS Rdr		KW	5,316	12,717	18,033	-$3.08	-$2.13	-$3.63	-$2.64	-16	-27	-43	-19	-34	-53	-9	21.5%
Fuel Cost	On	MWH	170,406	297,845	468,251	$35.02	$35.02	$35.09	$35.09	5,968	10,432	16,400	5,980	10,452	16,431	31	0.2%
Fuel Cost	Off	MWH	264,030	465,398	729,428	$22.91	$22.91	$22.97	$22.97	6,048	10,661	16,709	6,064	10,688	16,752	43	0.3%
Riders		KW	965,143	1,659,146	2,624,289	$1.02	$1.02	$0.00	$0.00	988	1,698	2,686	0	0	0	-2,686	-100.0%
Riders		MWH	434,436	763,243	1,197,679	$2.51	$2.51	$1.19	$1.19	1,091	1,917	3,008	518	911	1,429	-1,579	-52.5%
Total:										36,259	60,035	96,294	40,139	66,615	106,754	10,460	10.9%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A24 Peak-Ctrl Tier TOD Lg C&I Tr Transformed																	
Cust Chg		Bills	20	40	60	$57.34	$57.34	$61.73	$61.73	1	2	3	1	2	4	0	7.7%
Energy	On	MWH	46,838	87,766	134,604	$45.88	$45.88	$56.89	$56.89	2,149	4,027	6,176	2,664	4,993	7,657	1,482	24.0%
Energy	Off	MWH	75,721	143,663	219,384	$20.74	$20.74	$26.24	$26.24	1,570	2,980	4,550	1,987	3,769	5,756	1,206	26.5%
Energy Cr		MWH	26,625	52,176	78,801	-$15.18	-$15.18	-$17.75	-$17.75	-404	-792	-1,196	-473	-926	-1,399	-203	16.9%
Demand		KW	85,278	160,136	245,415	$13.24	$8.94	$15.29	$10.79	1,129	1,432	2,561	1,304	1,728	3,032	471	18.4%
Off Dmd		KW	2,421	5,028	7,449	$0.80	$0.80	$0.95	$0.95	2	4	6	2	5	7	1	18.8%
Control Dmd		KW	14,389	25,023	39,412	$7.33	$7.33	$9.18	$9.18	105	183	289	132	230	362	73	25.2%
Control Dmd		KW	0	0	0	$6.31	$6.31	$8.03	$8.03	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	50,432	92,694	143,126	$5.79	$5.79	$7.49	$7.49	292	537	829	378	694	1,072	243	29.4%
Control Dmd		KW	0	0	0	$5.60	$5.60	$7.29	$7.29	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$5.01	$5.01	$6.67	$6.67	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	97,542	181,038	278,579	$4.54	$4.54	$6.17	$6.17	443	822	1,265	602	1,117	1,719	454	35.9%
Fuel Cost	On	MWH	46,838	87,766	134,604	$35.02	$35.02	$35.09	$35.09	1,640	3,074	4,714	1,644	3,080	4,723	9	0.2%
Fuel Cost	Off	MWH	75,721	143,663	219,384	$22.91	$22.91	$22.97	$22.97	1,735	3,291	5,025	1,739	3,299	5,038	13	0.3%
Riders		KW	247,641	458,891	706,532	$1.02	$1.02	$0.00	$0.00	253	470	723	0	0	0	-723	-100.0%
Riders		MWH	122,559	231,429	353,988	$2.51	$2.51	$1.19	$1.19	308	581	889	146	276	422	-467	-52.5%
Total:										9,224	16,610	25,834	10,126	18,267	28,394	2,560	9.9%
A24 Peak-Ctrl Tier TOD Sm C&I Transmission																	
Cust Chg		Bills	0	0	0	$57.34	$57.34	$61.73	$61.73	0	0	0	0	0	0	0	0.0%
Energy	On	MWH	0	0	0	$45.78	$45.78	$56.78	$56.78	0	0	0	0	0	0	0	0.0%
Energy	Off	MWH	0	0	0	$20.64	$20.64	$26.13	$26.13	0	0	0	0	0	0	0	0.0%
Energy Cr		MWH	0	0	0	-$15.18	-$15.18	-$17.75	-$17.75	0	0	0	0	0	0	0	0.0%
Demand		KW	0	0	0	$12.44	$8.14	$14.34	$9.84	0	0	0	0	0	0	0	0.0%
Off Dmd		KW	0	0	0	$0.00	$0.00	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$6.53	$6.53	$8.23	$8.23	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$5.51	$5.51	$7.08	$7.08	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$4.99	$4.99	$6.54	$6.54	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$4.80	$4.80	$6.34	$6.34	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$4.21	$4.21	$5.72	$5.72	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$3.74	$3.74	$5.22	$5.22	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	0	0	0	$35.02	$35.02	$35.09	$35.09	0	0	0	0	0	0	0	0.0%
Fuel Cost	Off	MWH	0	0	0	$22.91	$22.91	$22.97	$22.97	0	0	0	0	0	0	0	0.0%
Riders		KW	0	0	0	$1.02	$1.02	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Riders		MWH	0	0	0	$2.51	$2.51	$1.19	$1.19	0	0	0	0	0	0	0	0.0%
Total:										0	0	0	0	0	0	0	0.0%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A24 Peak-Ctrl Tier TOD Lg C&I Transmission																	
Cust Chg		Bills	4	8	12	$57.34	$57.34	$61.73	$61.73	0	0	1	0	0	1	0	7.7%
Energy	On	MWH	455	1,082	1,536	$45.78	$45.78	$56.78	$56.78	21	50	70	26	61	87	17	24.0%
Energy	Off	MWH	1,214	2,481	3,696	$20.64	$20.64	$26.13	$26.13	25	51	76	32	65	97	20	26.6%
Energy Cr		MWH	0	39	39	-$15.18	-$15.18	-$17.75	-$17.75	0	-1	-1	0	-1	-1	0	16.9%
Demand		KW	0	0	0	$12.44	$8.14	$14.34	$9.84	0	0	0	0	0	0	0	0.0%
Off Dmd		KW	0	0	0	$0.00	$0.00	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$6.53	$6.53	$8.23	$8.23	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$5.51	$5.51	$7.08	$7.08	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$4.99	$4.99	$6.54	$6.54	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$4.80	$4.80	$6.34	$6.34	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	18,083	30,306	48,389	$4.21	$4.21	$5.72	$5.72	76	128	204	103	173	277	73	35.9%
Control Dmd		KW	0	0	0	$3.74	$3.74	$5.22	$5.22	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	455	1,082	1,536	$35.02	$35.02	$35.09	$35.09	16	38	54	16	38	54	0	0.2%
Fuel Cost	Off	MWH	1,214	2,481	3,696	$22.91	$22.91	$22.97	$22.97	28	57	85	28	57	85	0	0.3%
Riders		KW	18,083	30,306	48,389	$1.02	$1.02	$0.00	$0.00	19	31	50	0	0	0	-50	-100.0%
Riders		MWH	1,669	3,563	5,232	$2.51	$2.51	$1.19	$1.19	4	9	13	2	4	6	-7	-52.5%
Total:										189	363	552	207	399	606	54	9.8%
A27 Energy-Control Rider Sm C&I Secondary																	
Cust Chg		Bills	16	32	48	$57.34	$57.34	$61.73	$61.73	1	2	3	1	2	3	0	7.7%
Energy	On	MWH	55	115	170	$48.55	$48.55	$59.84	$59.84	3	6	8	3	7	10	2	23.3%
Energy	OnC	MWH	1,593	2,809	4,402	$46.47	$46.47	$57.75	$57.75	74	131	205	92	162	254	50	24.3%
Energy	Off	MWH	99	210	309	$23.41	$23.41	$29.19	$29.19	2	5	7	3	6	9	2	24.7%
Energy	OffC	MWH	2,356	4,232	6,588	$22.80	$22.80	$28.93	$28.93	54	96	150	68	122	191	40	26.9%
Energy Cr		MWH	531	1,107	1,637	-$15.18	-$15.18	-$17.75	-$17.75	-8	-17	-25	-9	-20	-29	-4	16.9%
Demand		KW	224	461	685	$14.79	$10.49	$17.09	$12.59	3	5	8	4	6	10	1	18.2%
Off Dmd		KW	12	65	77	$2.35	$2.35	$2.75	$2.75	0	0	0	0	0	0	0	17.0%
Control Dmd		KW	0	0	0	$7.15	$7.15	$9.09	$9.09	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	6,972	10,836	17,808	$6.56	$6.56	$8.47	$8.47	46	71	117	59	92	151	34	29.1%
Control Dmd		KW	3,447	7,516	10,963	$6.09	$6.09	$7.97	$7.97	21	46	67	27	60	87	21	30.9%
Fuel Cost	On	MWH	1,648	2,924	4,572	$35.02	$35.02	$35.09	$35.09	58	102	160	58	103	160	0	0.2%
Fuel Cost	Off	MWH	2,455	4,442	6,897	$22.91	$22.91	$22.97	$22.97	56	102	158	56	102	158	0	0.3%
Riders		KW	10,644	18,812	29,456	$1.02	$1.02	$0.00	$0.00	11	19	30	0	0	0	-30	-100.0%
Riders		MWH	4,103	7,366	11,469	$2.51	$2.51	$1.19	$1.19	10	19	29	5	9	14	-15	-52.5%
Total:										331	586	917	367	651	1,018	101	11.0%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units Summer	Billing Units Winter	Billing Units Annual	Present Rate Summer	Present Rate Winter	Proposed Rate Summer	Proposed Rate Winter	Present Revenues Summer	Present Revenues Winter	Present Revenues Annual	Proposed Revenues Summer	Proposed Revenues Winter	Proposed Revenues Annual	Increase Annual	Pct Inc. Annual
A27 Energy-Control Rider Lg C&I Secondary																	
Cust Chg		Bills	4	8	12	$57.34	$57.34	$61.73	$61.73	0	0	1	0	0	1	0	7.7%
Energy	On	MWH	0	0	0	$48.55	$48.55	$59.84	$59.84	0	0	0	0	0	0	0	0.0%
Energy	OnC	MWH	945	1,558	2,503	$46.47	$46.47	$57.75	$57.75	44	72	116	55	90	145	28	24.3%
Energy	Off	MWH	0	0	0	$23.41	$23.41	$29.19	$29.19	0	0	0	0	0	0	0	0.0%
Energy	OffC	MWH	1,589	2,591	4,180	$22.80	$22.80	$28.93	$28.93	36	59	95	46	75	121	26	26.9%
Energy Cr		MWH	667	1,039	1,707	-$15.18	-$15.18	-$17.75	-$17.75	-10	-16	-26	-12	-18	-30	-4	16.9%
Demand		KW	0	0	0	$14.79	$10.49	$17.09	$12.59	0	0	0	0	0	0	0	0.0%
Off Dmd		KW	5	26	31	$2.35	$2.35	$2.75	$2.75	0	0	0	0	0	0	0	17.0%
Control Dmd		KW	0	0	0	$7.15	$7.15	$9.09	$9.09	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	4,578	7,691	12,268	$6.56	$6.56	$8.47	$8.47	30	50	80	39	65	104	23	29.1%
Control Dmd		KW	0	0	0	$6.09	$6.09	$7.97	$7.97	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	945	1,558	2,503	$35.02	$35.02	$35.09	$35.09	33	55	88	33	55	88	0	0.2%
Fuel Cost	Off	MWH	1,589	2,591	4,180	$22.91	$22.91	$22.97	$22.97	36	59	96	36	60	96	0	0.3%
Riders		KW	4,578	7,691	12,268	$1.02	$1.02	$0.00	$0.00	5	8	13	0	0	0	-13	-100.0%
Riders		MWH	2,534	4,149	6,683	$2.51	$2.51	$1.19	$1.19	6	10	17	3	5	8	-9	-52.5%
Total:										181	299	480	200	331	532	52	10.8%
A27 Energy-Control Rider Sm C&I Primary																	
Cust Chg		Bills	4	8	12	$57.34	$57.34	$61.73	$61.73	0	0	1	0	0	1	0	7.7%
Energy	On	MWH	0	0	0	$47.50	$47.50	$58.64	$58.64	0	0	0	0	0	0	0	0.0%
Energy	OnC	MWH	1,655	3,198	4,853	$45.42	$45.42	$56.55	$56.55	75	145	220	94	181	274	54	24.5%
Energy	Off	MWH	0	0	0	$22.36	$22.36	$27.99	$27.99	0	0	0	0	0	0	0	0.0%
Energy	OffC	MWH	2,869	5,617	8,485	$21.75	$21.75	$27.73	$27.73	62	122	185	80	156	235	51	27.5%
Energy Cr		MWH	0	457	457	-$15.18	-$15.18	-$17.75	-$17.75	0	-7	-7	0	-8	-8	-1	16.9%
Demand		KW	0	0	0	$13.99	$9.69	$16.49	$11.99	0	0	0	0	0	0	0	0.0%
Off Dmd		KW	656	16	672	$1.55	$1.55	$2.15	$2.15	1	0	1	1	0	1	0	38.7%
Control Dmd		KW	0	0	0	$6.35	$6.35	$8.49	$8.49	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	6,972	10,836	17,808	$5.76	$5.76	$7.87	$7.87	40	62	103	55	85	140	38	36.6%
Control Dmd		KW	3,447	7,516	10,963	$5.29	$5.29	$7.37	$7.37	18	40	58	25	55	81	23	39.3%
Fuel Cost	On	MWH	1,655	3,198	4,853	$35.02	$35.02	$35.09	$35.09	58	112	170	58	112	170	0	0.2%
Fuel Cost	Off	MWH	2,869	5,617	8,485	$22.91	$22.91	$22.97	$22.97	66	129	194	66	129	195	1	0.3%
Riders		KW	10,420	18,352	28,771	$1.02	$1.02	$0.00	$0.00	11	19	29	0	0	0	-29	-100.0%
Riders		MWH	4,524	8,815	13,338	$2.51	$2.51	$1.19	$1.19	11	22	34	5	11	16	-18	-52.5%
Total:										343	645	988	384	721	1,106	118	12.0%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A27 Energy-Control Rider Lg C&I Primary																	
Cust Chg		Bills	12	24	36	$57.34	$57.34	$61.73	$61.73	1	1	2	1	1	2	0	7.7%
Energy	On	MWH	0	0	0	$47.50	$47.50	$58.64	$58.64	0	0	0	0	0	0	0	0.0%
Energy	OnC	MWH	4,255	8,173	12,428	$45.42	$45.42	$56.55	$56.55	193	371	565	241	462	703	138	24.5%
Energy	Off	MWH	0	0	0	$22.36	$22.36	$27.99	$27.99	0	0	0	0	0	0	0	0.0%
Energy	OffC	MWH	6,913	13,611	20,524	$21.75	$21.75	$27.73	$27.73	150	296	446	192	377	569	123	27.5%
Energy Cr		MWH	2,923	6,160	9,083	-$15.18	-$15.18	-$17.75	-$17.75	-44	-94	-138	-52	-109	-161	-23	16.9%
Demand		KW	0	0	0	$13.99	$9.69	$16.49	$11.99	0	0	0	0	0	0	0	0.0%
Off Dmd		KW	17	58	75	$1.55	$1.55	$2.15	$2.15	0	0	0	0	0	0	0	38.7%
Control Dmd		KW	0	668	668	$6.35	$6.35	$8.49	$8.49	0	4	4	0	6	6	1	33.7%
Control Dmd		KW	20,670	38,033	58,703	$5.76	$5.76	$7.87	$7.87	119	219	338	163	299	462	124	36.6%
Control Dmd		KW	0	0	0	$5.29	$5.29	$7.37	$7.37	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	4,255	8,173	12,428	$35.02	$35.02	$35.09	$35.09	149	286	435	149	287	436	1	0.2%
Fuel Cost	Off	MWH	6,913	13,611	20,524	$22.91	$22.91	$22.97	$22.97	158	312	470	159	313	471	1	0.3%
Riders		KW	20,670	38,701	59,371	$1.02	$1.02	$0.00	$0.00	21	40	61	0	0	0	-61	-100.0%
Riders		MWH	11,168	21,784	32,952	$2.51	$2.51	$1.19	$1.19	28	55	83	13	26	39	-43	-52.5%
Total:										776	1,491	2,267	865	1,662	2,528	261	11.5%
A27 Energy-Control Rider Lg C&I Tr Transformed																	
Cust Chg		Bills	8	16	24	$57.34	$57.34	$61.73	$61.73	0	1	1	0	1	1	0	7.7%
Energy	On	MWH	1,123	2,117	3,239	$45.88	$45.88	$56.89	$56.89	52	97	149	64	120	184	36	24.0%
Energy	OnC	MWH	41,618	76,536	118,154	$43.80	$43.80	$54.80	$54.80	1,823	3,352	5,175	2,281	4,194	6,474	1,299	25.1%
Energy	Off	MWH	2,121	3,880	6,001	$20.74	$20.74	$26.24	$26.24	44	80	124	56	102	157	33	26.5%
Energy	OffC	MWH	77,291	139,958	217,249	$20.13	$20.13	$25.98	$25.98	1,556	2,817	4,373	2,008	3,636	5,643	1,270	29.0%
Energy Cr		MWH	33,515	57,608	91,123	-$15.18	-$15.18	-$17.75	-$17.75	-509	-874	-1,383	-595	-1,023	-1,617	-234	16.9%
Demand		KW	4,463	8,357	12,821	$13.24	$8.94	$15.29	$10.79	59	75	134	68	90	158	25	18.4%
Off Dmd		KW	48,504	97,227	145,731	$0.80	$0.80	$0.95	$0.95	39	78	117	46	92	138	22	18.8%
Control Dmd		KW	0	0	0	$5.60	$5.60	$7.29	$7.29	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$5.01	$5.01	$6.67	$6.67	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	384,463	723,379	1,107,842	$4.54	$4.54	$6.17	$6.17	1,745	3,284	5,030	2,372	4,463	6,835	1,806	35.9%
Fuel Cost	On	MWH	42,740	78,653	121,393	$35.02	$35.02	$35.09	$35.09	1,497	2,755	4,252	1,500	2,760	4,260	8	0.2%
Fuel Cost	Off	MWH	79,412	143,837	223,250	$22.91	$22.91	$22.97	$22.97	1,819	3,295	5,114	1,824	3,303	5,127	13	0.3%
Riders		KW	388,927	731,736	1,120,663	$1.02	$1.02	$0.00	$0.00	398	749	1,147	0	0	0	-1,147	-100.0%
Riders		MWH	122,153	222,490	344,643	$2.51	$2.51	$1.19	$1.19	307	559	866	146	266	411	-454	-52.5%
Total:										8,830	16,268	25,098	9,769	18,005	27,774	2,676	10.7%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
Standby and Supplemental																	
Cust Chg	A14	Bills	4	8	12	$25.64	$25.64	$27.00	$27.00	0	0	0	0	0	0	0	5.3%
Cust Chg	A15	Bills	8	16	24	$25.64	$25.64	$27.00	$27.00	0	0	1	0	0	1	0	5.3%
Cust Chg	A15	Bills	8	16	24	$25.64	$25.64	$27.00	$27.00	0	0	1	0	0	1	0	5.3%
Cust Chg	A15	Bills	12	24	36	$25.64	$25.64	$27.00	$27.00	0	1	1	0	1	1	0	5.3%
Cust Chg	A15	Bills	8	16	24	$25.64	$25.64	$27.00	$27.00	0	0	1	0	0	1	0	5.3%
Cust Chg	A24	Bills	8	16	24	$25.64	$25.64	$27.00	$27.00	0	0	1	0	0	1	0	5.3%
Cust Chg	A24	Bills	4	8	12	$25.64	$25.64	$27.00	$27.00	0	0	0	0	0	0	0	5.3%
DemandU	A14	KW	2,000	4,000	6,000	$3.06	$3.06	$3.59	$3.59	6	12	18	7	14	22	3	17.3%
DemandU	A15	KW	2,532	5,064	7,596	$2.26	$2.26	$2.99	$2.99	6	11	17	8	15	23	6	32.3%
DemandU	A15	KW	12,000	24,000	36,000	$3.06	$3.06	$3.59	$3.59	37	73	110	43	86	129	19	17.3%
DemandU	A15	KW	8,000	16,000	24,000	$3.06	$3.06	$3.59	$3.59	24	49	73	29	57	86	13	17.3%
DemandU	A24	KW	13,000	26,000	39,000	$2.26	$2.26	$2.99	$2.99	29	59	88	39	78	117	28	32.3%
DemandS	A15	KW	20,000	40,000	60,000	$1.51	$1.51	$1.79	$1.79	30	60	91	36	72	107	17	18.5%
DemandS	A15	KW	269,858	457,527	727,385	$0.71	$0.71	$0.84	$0.84	192	325	516	227	384	611	95	18.3%
DemandS	A24	KW	16,000	32,000	48,000	$1.41	$1.41	$1.69	$1.69	23	45	68	27	54	81	13	19.9%
DmdSup	A15	KW	0	8,563	8,563	$1.85	$1.85	$2.21	$2.21	0	16	16	0	19	19	3	19.5%
DmdSup	A15	KW	28,000	56,000	84,000	$1.05	$1.05	$1.26	$1.26	29	59	88	35	71	106	18	20.0%
DmdSup	A24	KW	2,000	4,000	6,000	$2.60	$2.60	$3.41	$3.41	5	10	16	7	14	20	5	31.2%
DmdSup	A24	KW	14,000	24,500	38,500	$1.85	$1.85	$2.21	$2.21	26	45	71	31	54	85	14	19.5%
PkSurchg	A14	MWH	0	1	1	$63.12	$41.30	$72.76	$49.93	0	0	0	0	0	0	0	20.9%
PkSurchg	A15	MWH	13	43	55	$63.12	$41.30	$72.76	$49.93	1	2	3	1	2	3	0	19.1%
PkSurchg	A15	MWH	181	501	682	$63.12	$41.30	$72.76	$49.93	11	21	32	13	25	38	6	18.9%
PkSurchg	A15	MWH	4,015	7,817	11,832	$63.12	$41.30	$72.76	$49.93	253	323	576	292	390	682	106	18.4%
PkSurchg	A15	MWH	0	346	346	$63.12	$41.30	$72.76	$49.93	0	14	14	0	17	17	3	20.9%
PkSurchg	A15	MWH	1,454	975	2,429	$63.12	$41.30	$72.76	$49.93	92	40	132	106	49	154	22	17.0%
PkSurchg	A15	MWH	0	0	0	$63.12	$41.30	$72.76	$49.93	0	0	0	0	0	0	0	0.0%
Riders	A14	KW	2,000	4,000	6,000	$1.02	$1.02	$0.00	$0.00	2	4	6	0	0	0	-6	-100.0%
Riders	A15	KW	2,532	5,064	7,596	$1.02	$1.02	$0.00	$0.00	3	5	8	0	0	0	-8	-100.0%
Riders	A15	KW	12,000	24,000	36,000	$1.02	$1.02	$0.00	$0.00	12	25	37	0	0	0	-37	-100.0%
Riders	A15	KW	8,000	16,000	24,000	$1.02	$1.02	$0.00	$0.00	8	16	25	0	0	0	-25	-100.0%
Riders	A24	KW	13,000	26,000	39,000	$1.02	$1.02	$0.00	$0.00	13	27	40	0	0	0	-40	-100.0%
Riders	A15	KW	20,000	40,000	60,000	$1.02	$1.02	$0.00	$0.00	20	41	61	0	0	0	-61	-100.0%
Riders	A15	KW	269,858	457,527	727,385	$1.02	$1.02	$0.00	$0.00	276	468	744	0	0	0	-744	-100.0%
Riders	A24	KW	16,000	32,000	48,000	$1.02	$1.02	$0.00	$0.00	16	33	49	0	0	0	-49	-100.0%
Riders	A15	KW	0	8,563	8,563	$1.02	$1.02	$0.00	$0.00	0	9	9	0	0	0	-9	-100.0%
Riders	A15	KW	28,000	56,000	84,000	$1.02	$1.02	$0.00	$0.00	29	57	86	0	0	0	-86	-100.0%
Riders	A24	KW	2,000	4,000	6,000	$1.02	$1.02	$0.00	$0.00	2	4	6	0	0	0	-6	-100.0%
Riders	A24	KW	14,000	24,500	38,500	$1.02	$1.02	$0.00	$0.00	14	25	39	0	0	0	-39	-100.0%
Total:										1,163	1,882	3,045	901	1,404	2,306	-739	-24.3%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
PV Demand Credit Rider																	
Cust Chg	A14	Bills	200	400	600	$25.75	$25.75	$27.00	$27.00	5	10	15	5	11	16	1	4.9%
Cust Chg	A14	Bills	40	80	120	$25.75	$25.75	$27.00	$27.00	1	2	3	1	2	3	0	4.9%
Cust Chg	A15	Bills	120	240	360	$25.75	$25.75	$27.00	$27.00	3	6	9	3	6	10	0	4.9%
Cust Chg	A15	Bills	40	80	120	$25.75	$25.75	$27.00	$27.00	1	2	3	1	2	3	0	4.9%
Dmd Credit	A14	MWH	3,432	3,109	6,542	-$71.39	-$71.39	-$71.39	-$71.39	-245	-222	-467	-245	-222	-467	0	0.0%
Dmd Credit	A14	MWH	686	622	1,308	-$71.39	-$71.39	-$71.39	-$71.39	-49	-44	-93	-49	-44	-93	0	0.0%
Dmd Credit	A15	MWH	2,059	1,866	3,925	-$71.39	-$71.39	-$71.39	-$71.39	-147	-133	-280	-147	-133	-280	0	0.0%
Dmd Credit	A15	MWH	686	622	1,308	-$71.39	-$71.39	-$71.39	-$71.39	-49	-44	-93	-49	-44	-93	0	0.0%
Total:										-480	-423	-903	-479	-422	-902	2	-0.2%
A62 Real Time Pricing Lg C&I Primary																	
Cust Chg		Bills	12	24	36	$302.34	$302.34	$32.73	$32.73	4	7	11	0	1	1	-10	-89.2%
Energy		MWH	0	0	0	$0.00	$0.00	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Energy Cr		MWH	1,113	2,726	3,839	-$11.43	-$11.43	$0.00	$0.00	-13	-31	-44	0	0	0	44	-100.0%
Energy Cr		MWH	640	1,819	2,458	$0.00	$0.00	-$17.75	-$17.75	0	0	0	-11	-32	-44	-44	0.0%
LtdSurChg		MWH	51	102	153	$200.00	$200.00	$0.00	$0.00	10	20	31	0	0	0	-31	-100.0%
Demand		KW	16,981	28,164	45,145	$9.94	$9.94	$16.49	$11.99	169	280	449	311	396	707	259	57.7%
Dist Dmd		KW	29,378	48,725	78,103	$0.97	$0.97	$2.15	$2.15	28	47	76	3	5	8	-67	-88.9%
Energy		KW	2,649	4,785	7,434	$37.70	$27.15	$58.64	$58.64	100	130	230	155	281	436	206	89.7%
Energy		KW	4,823	8,777	13,600	$37.70	$27.15	$27.99	$27.99	182	238	420	135	246	381	-39	-9.4%
Fuel Cost	On	MWH	2,649	4,785	7,434	$35.02	$35.02	$35.09	$35.09	93	168	260	93	168	261	0	0.2%
Fuel Cost	Off	MWH	4,823	8,777	13,600	$22.91	$22.91	$22.97	$22.97	110	201	312	111	202	312	1	0.3%
Riders		KW	16,981	28,164	45,145	$1.02	$1.02	$0.00	$0.00	17	29	46	0	0	0	-46	-100.0%
Riders		MWH	7,472	13,562	21,034	$2.51	$2.51	$1.19	$1.19	19	34	53	9	16	25	-28	-52.5%
Total:										719	1,123	1,843	807	1,282	2,088	245	13.3%
A42 Siren Service Public Auth Secondary																	
HP		HP	15,204	30,408	45,612	$0.76	$0.76	$0.83	$0.83	12	23	35	13	25	38	3	9.2%
Total:										12	23	35	13	25	38	3	9.2%
Interdepartmental																	
Cust Chg			20	40	60	$0.00	$0.00	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Energy			3,295	3,813	7,108	$72.19	$67.25	$72.19	$67.25	238	256	494	238	256	494	0	0.0%
Fuel Cost			3,295	3,813	7,108	$28.01	$28.01	$28.08	$28.08	92	107	199	93	107	200	1	0.3%
Riders		MWH	3,295	3,813	7,108	$6.03	$6.03	$1.19	$1.19	20	23	43	4	5	8	-34	-80.2%
Total:										350	386	736	334	368	702	-34	-4.6%

[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS]

[HIGHLY CONFIDENTIAL TRADE SECRET ENDS]

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
		Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A07 Protective Ltg ResReg Secondary																
A100S	Lts	28,352	56,704	85,056	$7.34	$7.34	$8.59	$8.59	208	416	624	244	487	731	106	17.0%
A175M	Lts	10,960	21,920	32,880	$7.34	$7.34	$8.59	$8.59	80	161	241	94	188	282	41	17.0%
A250S	Lts	936	1,872	2,808	$11.64	$11.64	$13.77	$13.77	11	22	33	13	26	39	6	18.3%
A400M	Lts	252	504	756	$11.64	$11.64	$13.77	$13.77	3	6	9	3	7	10	2	18.3%
D250S	Lts	408	816	1,224	$12.62	$12.62	$14.37	$14.37	5	10	15	6	12	18	2	13.9%
D400S	Lts	112	224	336	$16.12	$16.12	$18.44	$18.44	2	4	5	2	4	6	1	14.4%
D400M	Lts	24	48	72	$16.19	$16.19	$18.50	$18.50	0	1	1	0	1	1	0	14.3%
D1000M	Lts	0	0	0	$25.52	$25.52	$26.56	$26.56	0	0	0	0	0	0	0	0.0%
Fuel Cost	MWH	1,606	4,498	6,104	$22.37	$22.37	$22.28	$22.28	36	101	137	36	100	136	-1	-0.4%
Riders	MWH	1,606	4,498	6,104	$2.51	$2.51	$1.19	$1.19	4	11	15	2	5	7	-8	-52.5%
Total:									350	731	1,081	400	830	1,231	149	13.8%
A07 Protective Ltg Sm C&I Secondary																
A100S	Lts	16,732	33,464	50,196	$7.34	$7.34	$8.59	$8.59	123	246	368	144	287	431	63	17.0%
A175M	Lts	6,800	13,600	20,400	$7.34	$7.34	$8.59	$8.59	50	100	150	58	117	175	26	17.0%
A250S	Lts	9,332	18,664	27,996	$11.64	$11.64	$13.77	$13.77	109	217	326	129	257	386	60	18.3%
A400M	Lts	3,868	7,736	11,604	$11.64	$11.64	$13.77	$13.77	45	90	135	53	107	160	25	18.3%
D250S	Lts	14,992	29,984	44,976	$12.62	$12.62	$14.37	$14.37	189	378	568	215	431	646	79	13.9%
D400S	Lts	20,312	40,624	60,936	$16.12	$16.12	$18.44	$18.44	327	655	982	375	749	1,124	141	14.4%
D400M	Lts	1,296	2,592	3,888	$16.19	$16.19	$18.50	$18.50	21	42	63	24	48	72	9	14.3%
D1000M	Lts	116	232	348	$25.52	$25.52	$26.56	$26.56	3	6	9	3	6	9	0	4.1%
Fuel Cost	MWH	5,985	17,240	23,225	$22.37	$22.37	$22.28	$22.28	134	386	520	133	384	517	-2	-0.4%
Riders	MWH	5,985	17,240	23,225	$2.51	$2.51	$1.19	$1.19	15	43	58	7	21	28	-31	-52.5%
Total:									1,016	2,163	3,179	1,141	2,407	3,548	369	11.6%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
		Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A30 St Ltg System Lighting Secondary																
OH70S	Lts	0	0	0	$9.63	$9.63	$12.96	$12.96	0	0	0	0	0	0	0	0.0%
OH100S	Lts	212	424	636	$10.17	$10.17	$13.55	$13.55	2	4	6	3	6	9	2	33.2%
OH150S	Lts	264	528	792	$10.95	$10.95	$14.56	$14.56	3	6	9	4	8	12	3	33.0%
OH200S	Lts	72	144	216	$12.88	$12.88	$16.40	$16.40	1	2	3	1	2	4	1	27.3%
OH250S	Lts	52	104	156	$13.87	$13.87	$17.50	$17.50	1	1	2	1	2	3	1	26.2%
OH400S	Lts	12	24	36	$16.85	$16.85	$21.02	$21.02	0	0	1	0	1	1	0	24.7%
OH175H	Lts	0	0	0	$14.98	$14.98	$17.84	$17.84	0	0	0	0	0	0	0	0.0%
OH40LED	Lts	204,912	409,824	614,736	$10.32	$10.32	$13.07	$13.07	2,115	4,229	6,344	2,678	5,356	8,035	1,691	26.6%
OH75LED	Lts	56,916	113,832	170,748	$11.01	$11.01	$13.76	$13.76	627	1,253	1,880	783	1,566	2,349	470	25.0%
OH165LED	Lts	11,044	22,088	33,132	$14.46	$14.46	$16.90	$16.90	160	319	479	187	373	560	81	16.9%
OH250LED	Lts	96	192	288	$17.98	$17.98	$20.31	$20.31	2	3	5	2	4	6	1	13.0%
UG70S	Lts	200	400	600	$19.54	$19.54	$23.59	$23.59	4	8	12	5	9	14	2	20.7%
UG100S	Lts	9,060	18,120	27,180	$20.07	$20.07	$24.18	$24.18	182	364	546	219	438	657	112	20.5%
UG150S	Lts	488	976	1,464	$20.86	$20.86	$25.19	$25.19	10	20	31	12	25	37	6	20.8%
UG250S	Lts	172	344	516	$23.38	$23.38	$27.92	$27.92	4	8	12	5	10	14	2	19.4%
UG400S	Lts	0	0	0	$26.06	$26.06	$31.28	$31.28	0	0	0	0	0	0	0	0.0%
UG175H	Lts	0	0	0	$27.90	$27.90	$31.92	$31.92	0	0	0	0	0	0	0	0.0%
UG40LED	Lts	75,828	151,656	227,484	$20.22	$20.22	$23.70	$23.70	1,533	3,066	4,600	1,797	3,594	5,391	792	17.2%
UG75LED	Lts	16,348	32,696	49,044	$20.91	$20.91	$24.39	$24.39	342	684	1,026	399	797	1,196	171	16.6%
UG165LED	Lts	3,636	7,272	10,908	$23.96	$23.96	$27.31	$27.31	87	174	261	99	199	298	37	14.0%
UG250LED	Lts	0	0	0	$27.19	$27.19	$30.57	$30.57	0	0	0	0	0	0	0	0.0%
Dec100S	Lts	280	560	840	$31.67	$31.67	$35.83	$35.83	9	18	27	10	20	30	3	13.1%
Dec150S	Lts	56	112	168	$32.84	$32.84	$37.04	$37.04	2	4	6	2	4	6	1	12.8%
Dec250S	Lts	216	432	648	$34.89	$34.89	$39.52	$39.52	8	15	23	9	17	26	3	13.3%
Dec400S	Lts	0	0	0	$37.38	$37.38	$42.78	$42.78	0	0	0	0	0	0	0	0.0%
PO70S	Lts	1,008	2,016	3,024	$5.97	$5.97	$6.56	$6.56	6	12	18	7	13	20	2	9.9%
PO100S	Lts	40,316	80,632	120,948	$6.66	$6.66	$7.35	$7.35	269	537	806	296	593	889	83	10.4%
PO150S	Lts	16,628	33,256	49,884	$7.54	$7.54	$8.35	$8.35	125	251	376	139	278	417	40	10.7%
PO250S	Lts	5,844	11,688	17,532	$9.61	$9.61	$10.70	$10.70	56	112	168	63	125	188	19	11.3%
PO400S	Lts	260	520	780	$12.42	$12.42	$13.89	$13.89	3	6	10	4	7	11	1	11.8%
PO175H	Lts	128	256	384	$13.54	$13.54	$14.90	$14.90	2	3	5	2	4	6	1	10.0%
PO40LED	Lts	2,432	4,864	7,296	$4.90	$4.90	$5.37	$5.37	12	24	36	13	26	39	3	9.6%
PO75LED	Lts	6,680	13,360	20,040	$5.49	$5.49	$6.03	$6.03	37	73	110	40	81	121	11	9.8%
PO165LED	Lts	2,292	4,584	6,876	$7.05	$7.05	$7.79	$7.79	16	32	48	18	36	54	5	10.5%
PO250LED	Lts	0	0	0	$8.93	$8.93	$9.91	$9.91	0	0	0	0	0	0	0	0.0%
POSurChg	Amt	39,188	78,377	117,565	$1.00	$1.00	$1.00	$1.00	39	78	118	39	78	118	0	0.0%
Fuel Cost	MWH	7,066	24,020	31,086	$22.37	$22.37	$22.28	$22.28	158	537	695	157	535	693	-3	-0.4%
Riders	MWH	7,066	24,020	31,086	$2.51	$2.51	$1.19	$1.19	18	60	78	8	29	37	-41	-52.5%
Total:									5,831	11,908	17,739	7,002	14,236	21,237	3,499	19.7%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
		Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A32 St Ltg Energy Lighting Secondary																
50S	Lts	15,364	30,728	46,092	$1.32	$1.32	$1.53	$1.53	20	41	61	24	47	71	10	15.9%
70S	Lts	49,980	99,960	149,940	$1.67	$1.67	$1.93	$1.93	83	167	250	96	193	289	39	15.6%
100S	Lts	40,724	81,448	122,172	$2.22	$2.22	$2.54	$2.54	90	181	271	103	207	310	39	14.4%
150S	Lts	18,220	36,440	54,660	$3.04	$3.04	$3.45	$3.45	55	111	166	63	126	189	22	13.5%
200S	Lts	5,988	11,976	17,964	$4.05	$4.05	$4.58	$4.58	24	49	73	27	55	82	10	13.1%
250S	Lts	23,212	46,424	69,636	$5.12	$5.12	$5.77	$5.77	119	238	357	134	268	402	45	12.7%
400S	Lts	3,784	7,568	11,352	$7.79	$7.79	$8.74	$8.74	29	59	88	33	66	99	11	12.2%
750S	Lts	184	368	552	$13.37	$13.37	$14.96	$14.96	2	5	7	3	6	8	1	11.9%
100M	Lts	308	616	924	$2.37	$2.37	$2.71	$2.71	1	1	2	1	2	3	0	14.3%
175M	Lts	2,276	4,552	6,828	$3.53	$3.53	$4.00	$4.00	8	16	24	9	18	27	3	13.3%
250M	Lts	380	760	1,140	$4.78	$4.78	$5.39	$5.39	2	4	5	2	4	6	1	12.8%
400M	Lts	1,332	2,664	3,996	$7.45	$7.45	$8.37	$8.37	10	20	30	11	22	33	4	12.3%
700M	Lts	216	432	648	$12.39	$12.39	$13.87	$13.87	3	5	8	3	6	9	1	11.9%
1000M	Lts	20	40	60	$17.24	$17.24	$19.27	$19.27	0	1	1	0	1	1	0	11.8%
1F72HO	Lts	36	72	108	$3.61	$3.61	$3.61	$3.61	0	0	0	0	0	0	0	0.0%
Fuel Cost	MWH	5,854	19,900	25,754	$22.37	$22.37	$22.28	$22.28	131	445	576	130	443	574	-2	-0.4%
Riders	MWH	5,854	19,900	25,754	$2.51	$2.51	$1.19	$1.19	15	50	65	7	24	31	-34	-52.5%
Total:									594	1,392	1,986	648	1,487	2,135	149	7.5%
A34 St Ltg Energy Mtrd Lighting Secondary																
Cust Chg	Bills	8,996	17,993	26,989	$5.00	$5.00	$5.50	$5.50	45	90	135	49	99	148	13	10.0%
Energy	MWH	7,809	26,545	34,354	$45.34	$45.34	$49.01	$49.01	354	1,204	1,558	383	1,301	1,684	126	8.1%
Fuel Cost	MWH	7,809	26,545	34,354	$22.37	$22.37	$22.28	$22.28	175	594	769	174	591	765	-3	-0.4%
Riders	MWH	7,809	26,545	34,354	$2.51	$2.51	$1.19	$1.19	20	67	86	9	32	41	-45	-52.5%
Total:									593	1,954	2,547	615	2,023	2,639	91	3.6%
A37 St Ltg St. Paul Lighting Secondary																
OH100S	Lts	4,308	8,616	12,924	$5.35	$5.35	$5.64	$5.64	23	46	69	24	49	73	4	5.4%
OH150S	Lts	2,376	4,752	7,128	$6.07	$6.07	$6.32	$6.32	14	29	43	15	30	45	2	4.1%
OH250S	Lts	4	8	12	$8.78	$8.78	$9.01	$9.01	0	0	0	0	0	0	0	2.6%
Fuel Cost	MWH	216	733	948	$22.37	$22.37	$22.28	$22.28	5	16	21	5	16	21	0	-0.4%
Riders	MWH	216	733	948	$2.51	$2.51	$1.19	$1.19	1	2	2	0	1	1	-1	-52.5%
Total:									43	93	136	44	96	140	4	3.1%
Retail + Interdepartmental Total:									1,199,326	1,881,618	3,080,944	1,339,259	2,088,292	3,427,551	346,607	11.3%
Interdepartmental without Base Increase:									350	386	736	334	368	702	-34	-4.6%
Retail:									1,198,976	1,881,232	3,080,208	1,338,924	2,087,924	3,426,848	346,640	11.3%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
		Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A01 Res OH ResReg Secondary																
Cust Chg	Bills	3,017,334	6,038,871	9,056,205	$8.55	$8.55	$10.08	$10.08	25,812	51,660	77,472	30,411	60,864	91,275	13,804	17.8%
Energy	MWH	1,713,618	2,692,082	4,405,700	$103.01	$88.03	$130.20	$113.22	176,520	236,984	413,504	223,113	304,797	527,911	114,407	27.7%
SvrSwtchAC	MWH	592,449	0	592,449	-$20.13	$0.00	-$10.00	$0.00	-11,926	0	-11,926	-7,369	0	-7,369	4,558	-38.2%
SvrSwtchWH	MWH	12,664	23,010	35,674	-$2.68	-$2.30	-$2.00	-$2.00	-34	-53	-87	-27	-49	-76	11	-13.0%
LowIncCredit	MWH	141,876	283,752	425,628	-$15.00	-$15.00	-$15.00	-$15.00	-2,128	-4,256	-6,384	-2,128	-4,256	-6,384	0	0.0%
Fuel Cost	MWH	1,713,618	2,692,082	4,405,700	$31.19	$27.16	$30.95	$26.95	53,456	73,108	126,564	53,042	72,542	125,584	-979	-0.8%
Riders	MWH	1,713,618	2,692,082	4,405,700	$6.00	$6.00	$1.31	$1.31	10,290	16,165	26,455	2,248	3,532	5,780	-20,675	-78.2%
Total:									251,989	373,607	625,596	299,291	437,430	736,721	111,125	17.8%
A01 Res OH ResSH Secondary																
Cust Chg	Bills	105,596	210,650	316,246	$10.55	$10.55	$12.08	$12.08	1,115	2,223	3,338	1,275	2,544	3,820	482	14.4%
Energy	MWH	53,809	188,613	242,422	$103.01	$59.88	$130.20	$78.11	5,543	11,294	16,837	7,006	14,733	21,738	4,901	29.1%
SvrSwtchAC	MWH	8,626	0	8,626	-$20.13	$0.00	-$10.00	$0.00	-174	0	-174	-89	0	-89	84	-48.6%
SvrSwtchWH	MWH	1,259	3,843	5,102	-$2.68	-$1.74	-$2.00	-$2.00	-3	-7	-10	-3	-8	-11	-1	7.5%
LowIncCredit	MWH	4,954	9,909	14,863	-$15.00	-$15.00	-$15.00	-$15.00	-74	-149	-223	-74	-149	-223	0	0.0%
Fuel Cost	MWH	53,809	188,613	242,422	$31.19	$27.16	$30.95	$26.95	1,679	5,122	6,801	1,666	5,082	6,748	-53	-0.8%
Riders	MWH	53,809	188,613	242,422	$6.00	$6.00	$1.31	$1.31	323	1,133	1,456	71	247	318	-1,138	-78.2%
Total:									8,408	19,617	28,025	9,851	22,450	32,301	4,277	15.3%
A03 Res UG ResReg Secondary																
Cust Chg	Bills	1,571,401	3,144,992	4,716,393	$10.55	$10.55	$12.08	$12.08	16,585	33,194	49,779	18,981	37,988	56,968	7,189	14.4%
Energy	MWH	1,336,890	2,044,862	3,381,753	$103.01	$88.03	$130.20	$113.22	137,713	180,009	317,722	174,063	231,519	405,582	87,860	27.7%
SvrSwtchAC	MWH	667,916	0	667,916	-$20.13	$0.00	-$10.00	$0.00	-13,446	0	-13,446	-7,372	0	-7,372	6,073	-45.2%
SvrSwtchWH	MWH	6,140	10,880	17,020	-$2.68	-$2.30	-$2.00	-$2.00	-16	-25	-42	-13	-23	-36	5	-13.1%
LowIncCredit	MWH	73,888	147,776	221,664	-$15.00	-$15.00	-$15.00	-$15.00	-1,108	-2,217	-3,325	-1,108	-2,217	-3,325	0	0.0%
Fuel Cost	MWH	1,336,890	2,044,862	3,381,753	$31.19	$27.16	$30.95	$26.95	41,704	55,532	97,236	41,381	55,102	96,483	-753	-0.8%
Riders	MWH	1,336,890	2,044,862	3,381,753	$6.00	$6.00	$1.31	$1.31	8,028	12,279	20,306	1,754	2,683	4,436	-15,870	-78.2%
Total:									189,460	278,772	468,232	227,685	325,051	552,737	84,505	18.0%
A03 Res UG ResSH Secondary																
Cust Chg	Bills	36,950	73,711	110,661	$12.55	$12.55	$14.08	$14.08	464	925	1,389	520	1,038	1,558	169	12.1%
Energy	MWH	26,012	91,179	117,191	$103.01	$59.88	$130.20	$78.11	2,680	5,460	8,139	3,387	7,122	10,509	2,369	29.1%
SvrSwtchAC	MWH	9,256	0	9,256	-$20.13	$0.00	-$10.00	$0.00	-186	0	-186	-92	0	-92	94	-50.7%
SvrSwtchWH	MWH	1,071	3,719	4,790	-$2.68	-$1.74	-$2.00	-$2.00	-3	-6	-9	-2	-8	-10	-1	8.7%
LowIncCredit	MWH	1,734	3,467	5,201	-$15.00	-$15.00	-$15.00	-$15.00	-26	-52	-78	-26	-52	-78	0	0.0%
Fuel Cost	MWH	26,012	91,179	117,191	$31.19	$27.16	$30.95	$26.95	811	2,476	3,288	805	2,457	3,262	-25	-0.8%
Riders	MWH	26,012	91,179	117,191	$6.00	$6.00	$1.31	$1.31	156	548	704	34	120	154	-550	-78.2%
Total:									3,896	9,350	13,246	4,626	10,676	15,303	2,056	15.5%
A00 WtrHeating ResSH Secondary																
Cust Chg	Bills	179	355	534	$0.00	$0.00	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Energy	MWH	26	93	119	$103.01	$88.03	$130.20	$113.22	3	8	11	3	11	14	3	28.1%
Fuel Cost	MWH	26	93	119	$31.19	$27.16	$30.95	$26.95	1	3	3	1	3	3	0	-0.8%
Riders	MWH	26	93	119	$6.00	$6.00	$1.31	$1.31	0	1	1	0	0	0	-1	-78.2%
Total:									4	11	15	4	13	17	2	16.5%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A02 Res TOD OH ResReg Secondary																	
Cust Chg		Bills	1,244	2,491	3,735	$10.55	$10.55	$12.08	$12.08	13	26	39	15	30	45	6	14.4%
Energy	On	MWH	291	541	832	$204.97	$165.08	$253.57	$208.27	60	89	149	74	113	187	38	25.2%
Energy	Off	MWH	617	1,344	1,961	$41.70	$41.70	$56.24	$56.24	26	56	82	35	76	110	29	34.9%
Fuel Cost		MWH	908	1,885	2,793	$31.19	$27.16	$30.95	$26.95	28	51	80	28	51	79	-1	-0.8%
Riders		MWH	908	1,885	2,793	$6.00	$6.00	$1.31	$1.31	5	11	17	1	2	4	-13	-78.2%
Total:										132	234	366	153	272	424	58	15.8%
A02 Res TOD OH ResSH Secondary																	
Cust Chg		Bills	168	339	507	$12.55	$12.55	$14.08	$14.08	2	4	6	2	5	7	1	12.1%
Energy	On	MWH	53	186	240	$204.97	$92.84	$253.57	$117.71	11	17	28	13	22	35	7	25.6%
Energy	Off	MWH	116	407	523	$41.70	$41.70	$56.24	$56.24	5	17	22	7	23	29	8	34.9%
Fuel Cost		MWH	169	593	762	$31.19	$27.16	$30.95	$26.95	5	16	21	5	16	21	0	-0.8%
Riders		MWH	169	593	762	$6.00	$6.00	$1.31	$1.31	1	4	5	0	1	1	-4	-78.2%
Total:										24	58	82	28	66	94	12	14.4%
A08 Res EV ResReg Secondary																	
Cust Chg		Bills	5,667	11,025	16,692	$4.95	$4.95	$5.50	$5.50	28	55	83	31	61	92	9	11.1%
Energy	On	MWH	1,778	3,626	5,404	$204.97	$165.08	$253.57	$208.27	364	599	963	451	755	1,206	243	25.2%
Energy	Off	MWH	22,521	45,862	68,383	$41.70	$41.70	$56.24	$56.24	939	1,912	2,852	1,267	2,579	3,846	994	34.9%
Fuel Cost		MWH	24,299	49,488	73,787	$31.19	$27.16	$30.95	$26.95	758	1,344	2,102	752	1,334	2,086	-16	-0.8%
Riders		MWH	24,299	49,488	73,787	$6.00	$6.00	$1.31	$1.31	146	297	443	32	65	97	-346	-78.2%
Total:										2,236	4,207	6,442	2,533	4,794	7,326	884	13.7%
A80 Res EV Pilot Bund ResReg Secondary																	
Cust Chg		Bills	888	1,728	2,616	$17.47	$17.47	$18.00	$18.00	16	30	46	16	31	47	1	3.0%
Energy	On	MWH	103	209	311	$204.97	$165.08	$253.57	$208.27	21	34	55	26	43	69	14	25.2%
Energy	Off	MWH	5,321	10,820	16,141	$41.70	$41.70	$56.24	$56.24	222	451	673	299	608	908	235	34.9%
Fuel Cost		MWH	5,424	11,028	16,452	$31.19	$27.16	$30.95	$26.95	169	299	469	168	297	465	-4	-0.8%
Riders		MWH	5,424	11,028	16,452	$6.00	$6.00	$1.31	$1.31	33	66	99	7	14	22	-77	-78.2%
Total:										460	882	1,342	516	995	1,511	169	12.6%
A81 Res EV Pilot PrePay ResReg Secondary																	
Cust Chg		Bills	428	832	1,260	$7.10	$7.10	$7.50	$7.50	3	6	9	3	6	9	1	5.6%
Energy	On	MWH	9	19	28	$204.97	$165.08	$253.57	$208.27	2	3	5	2	4	6	1	25.2%
Energy	Off	MWH	1,704	3,464	5,168	$41.70	$41.70	$56.24	$56.24	71	144	216	96	195	291	75	34.9%
Fuel Cost		MWH	1,713	3,483	5,196	$31.19	$27.16	$30.95	$26.95	53	95	148	53	94	147	-1	-0.8%
Riders		MWH	1,713	3,483	5,196	$6.00	$6.00	$1.31	$1.31	10	21	31	2	5	7	-24	-78.2%
Total:										140	269	409	157	303	460	51	12.6%
A04 Res TOD UG ResReg Secondary																	
Cust Chg		Bills	1,166	2,335	3,501	$12.55	$12.55	$14.08	$14.08	15	29	44	16	33	49	5	12.1%
Energy	On	MWH	357	589	945	$204.97	$165.08	$253.57	$208.27	73	97	170	91	123	213	43	25.1%
Energy	Off	MWH	719	1,420	2,139	$41.70	$41.70	$56.24	$56.24	30	59	89	40	80	120	31	34.9%
Fuel Cost		MWH	1,076	2,009	3,084	$31.19	$27.16	$30.95	$26.95	34	55	88	33	54	87	-1	-0.8%
Riders		MWH	1,076	2,009	3,084	$6.00	$6.00	$1.31	$1.31	6	12	19	1	3	4	-14	-78.2%
Total:										158	252	410	182	292	474	64	15.6%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A04 Res TOD UG ResSH Secondary																	
Cust Chg		Bills	164	329	493	$14.55	$14.55	$16.08	$16.08	2	5	7	3	5	8	1	10.5%
Energy	On	MWH	44	154	198	$204.97	$92.84	$253.57	$117.71	9	14	23	11	18	29	6	25.6%
Energy	Off	MWH	108	377	485	$41.70	$41.70	$56.24	$56.24	4	16	20	6	21	27	7	34.9%
Fuel Cost		MWH	151	531	682	$31.19	$27.16	$30.95	$26.95	5	14	19	5	14	19	0	-0.8%
Riders		MWH	151	531	682	$6.00	$6.00	$1.31	$1.31	1	3	4	0	1	1	-3	-78.2%
Total:										21	52	74	25	60	84	10	14.1%
A05 EnergyCtrl N/D ResReg Secondary																	
Cust Chg		Bills	2,477	4,955	7,432	$4.95	$4.95	$5.50	$5.50	12	25	37	14	27	41	4	11.1%
Energy		MWH	1,081	5,191	6,272	$44.87	$44.87	$61.73	$61.73	49	233	281	67	320	387	106	37.6%
Opt Energy		MWH	24	106	130	$103.01	$44.87	$130.20	$61.73	3	5	7	3	7	10	2	33.7%
Fuel Cost		MWH	1,106	5,297	6,403	$31.19	$27.16	$30.95	$26.95	34	144	178	34	143	177	-1	-0.8%
Riders		MWH	1,106	5,297	6,403	$6.00	$6.00	$1.31	$1.31	7	32	38	1	7	8	-30	-78.2%
Total:										104	438	542	119	504	623	81	14.9%
A05 EnergyCtrl N/D ResSH Secondary																	
Cust Chg		Bills	10,858	21,662	32,520	$4.95	$4.95	$5.50	$5.50	54	107	161	60	119	179	18	11.1%
Energy		MWH	6,947	23,836	30,783	$44.87	$44.87	$61.73	$61.73	312	1,070	1,381	429	1,471	1,900	519	37.6%
Opt Energy		MWH	763	3,189	3,952	$103.01	$44.87	$130.20	$61.73	79	143	222	99	197	296	75	33.6%
Fuel Cost		MWH	7,710	27,025	34,735	$31.19	$27.16	$30.95	$26.95	241	734	974	239	728	967	-8	-0.8%
Riders		MWH	7,710	27,025	34,735	$6.00	$6.00	$1.31	$1.31	46	162	209	10	35	46	-163	-78.2%
Total:										731	2,216	2,947	837	2,551	3,388	441	15.0%
A05 EnergyCtrl N/D Sm C&I Secondary																	
Cust Chg		Bills	452	904	1,356	$4.95	$4.95	$5.50	$5.50	2	4	7	2	5	7	1	11.1%
Energy		MWH	248	1,444	1,691	$44.87	$44.87	$61.73	$61.73	11	65	76	15	89	104	29	37.6%
Opt Energy		MWH	3	105	108	$92.56	$44.87	$117.80	$61.73	0	5	5	0	7	7	2	37.0%
Fuel Cost		MWH	251	1,549	1,800	$31.59	$27.50	$32.36	$28.17	8	43	51	8	44	52	1	2.4%
Riders		MWH	251	1,549	1,800	$5.88	$5.88	$1.31	$1.31	1	9	11	0	2	2	-8	-77.7%
Total:										23	126	149	27	146	173	24	16.2%
A06 Limited Off-Peak ResReg Secondary																	
Cust Chg		Bills	1,500	3,001	4,501	$4.95	$4.95	$5.50	$5.50	7	15	22	8	17	25	2	11.1%
Energy	On	MWH	21	78	99	$360.00	$360.00	$425.00	$425.00	8	28	36	9	33	42	6	18.1%
Energy	Off	MWH	203	2,292	2,494	$36.65	$36.65	$50.94	$50.94	7	84	91	10	117	127	36	39.0%
Fuel Cost		MWH	224	2,370	2,594	$31.19	$27.16	$30.95	$26.95	7	64	71	7	64	71	-1	-0.8%
Riders		MWH	224	2,370	2,594	$6.00	$6.00	$1.31	$1.31	1	14	16	0	3	3	-12	-78.2%
Total:										31	206	236	35	233	268	32	13.5%
A06 Limited Off-Peak ResSH Secondary																	
Cust Chg		Bills	28	51	79	$4.95	$4.95	$5.50	$5.50	0	0	0	0	0	0	0	11.1%
Energy	On	MWH	0	1	1	$360.00	$360.00	$425.00	$425.00	0	0	0	0	0	0	0	18.1%
Energy	Off	MWH	25	89	115	$36.65	$36.65	$50.94	$50.94	1	3	4	1	5	6	2	39.0%
Fuel Cost		MWH	26	90	115	$31.19	$27.16	$30.95	$26.95	1	2	3	1	2	3	0	-0.8%
Riders		MWH	26	90	115	$6.00	$6.00	$1.31	$1.31	0	1	1	0	0	0	-1	-78.2%
Total:										2	7	9	2	8	10	1	13.2%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A06 Limited Off-Peak Sm C&I Secondary																	
Cust Chg		Bills	207	412	619	$10.00	$10.00	$11.00	$11.00	2	4	6	2	5	7	1	10.0%
Cust Chg		Bills	143	287	430	$13.60	$13.60	$15.00	$15.00	2	4	6	2	4	6	1	10.3%
Cust Chg		Bills	0	0	0	$60.00	$60.00	$60.00	$60.00	0	0	0	0	0	0	0	0.0%
Energy	On	MWH	48	90	138	$360.00	$360.00	$425.00	$425.00	17	32	50	20	38	58	9	18.1%
Energy	Off	MWH	27	613	639	$36.65	$36.65	$50.94	$50.94	1	22	23	1	31	33	9	39.0%
Energy	Off	MWH	293	727	1,020	$36.65	$36.65	$50.94	$50.94	11	27	37	15	37	52	15	39.0%
Energy	Off	MWH	0	0	0	$35.60	$35.60	$49.70	$49.70	0	0	0	0	0	0	0	0.0%
Fuel Cost		MWH	367	1,429	1,797	$31.59	$27.50	$32.36	$28.17	12	39	51	12	40	52	1	2.4%
Riders		MWH	367	1,429	1,797	$5.88	$5.88	$1.31	$1.31	2	8	11	0	2	2	-8	-77.7%
Total:										47	137	184	53	157	211	27	14.6%
A09 SmallGen UnMtrd Sm C&I Secondary																	
Cust Chg		Bills	404	807	1,211	$8.78	$8.78	$10.23	$10.23	4	7	11	4	8	12	2	16.5%
Energy		MWH	8	16	23	$92.56	$77.57	$117.80	$100.81	1	1	2	1	2	2	1	29.0%
Fuel Cost		MWH	8	16	23	$31.59	$27.50	$32.36	$28.17	0	0	1	0	0	1	0	2.4%
Riders		MWH	8	16	23	$5.88	$5.88	$1.31	$1.31	0	0	0	0	0	0	0	-77.7%
Total:										5	9	13	5	10	16	2	16.7%
A10 SmallGen Sm C&I Secondary																	
Cust Chg		Bills	302,346	604,343	906,689	$10.78	$10.78	$12.23	$12.23	3,259	6,515	9,774	3,699	7,393	11,091	1,317	13.5%
Energy		MWH	247,294	495,458	742,751	$92.56	$77.57	$117.80	$100.81	22,889	38,433	61,322	29,131	49,947	79,078	17,756	29.0%
SvrSwtchAC		Tons	146,725	0	146,725	-$5.00	$0.00	-$5.00	$0.00	-734	0	-734	-734	0	-734	0	0.0%
Fuel Cost		MWH	247,294	495,458	742,751	$31.59	$27.50	$32.36	$28.17	7,811	13,624	21,436	8,001	13,956	21,957	522	2.4%
Riders		MWH	247,294	495,458	742,751	$5.88	$5.88	$1.31	$1.31	1,455	2,916	4,371	324	650	974	-3,396	-77.7%
Total:										34,682	61,487	96,169	40,422	71,946	112,367	16,199	16.8%
A40 Small Mun Pumping Public Auth Secondary																	
Cust Chg		Bills	3,724	7,453	11,177	$10.78	$10.78	$12.23	$12.23	40	80	120	46	91	137	16	13.5%
Energy		MWH	2,239	4,813	7,053	$92.56	$77.57	$117.80	$100.81	207	373	581	264	485	749	168	29.0%
Fuel Cost		MWH	2,239	4,813	7,053	$31.59	$27.50	$32.36	$28.17	71	132	203	72	136	208	5	2.4%
Riders		MWH	2,239	4,813	7,053	$5.88	$5.88	$1.31	$1.31	13	28	42	3	6	9	-32	-77.7%
Total:										331	614	946	385	718	1,103	157	16.6%
A11 WtrHeating Sm C&I Secondary																	
Cust Chg		Bills	320	641	961	$0.00	$0.00	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Energy		MWH	67	147	214	$92.56	$77.57	$117.80	$100.81	6	11	18	8	15	23	5	29.0%
Fuel Cost		MWH	67	147	214	$31.59	$27.50	$32.36	$28.17	2	4	6	2	4	6	0	2.4%
Riders		MWH	67	147	214	$5.88	$5.88	$1.31	$1.31	0	1	1	0	0	0	-1	-77.7%
Total:										9	16	25	10	19	29	4	17.1%
A13 Direct Current Sm C&I Secondary																	
Cust Chg		Bills	12	24	36	$10.78	$10.78	$12.23	$12.23	0	0	0	0	0	0	0	13.5%
Energy		MWH	1	2	2	$92.56	$77.57	$117.80	$100.81	0	0	0	0	0	0	0	28.9%
Demand		KW	676	1,352	2,028	$3.61	$3.61	$4.05	$4.05	2	5	7	3	5	8	1	12.2%
Fuel Cost		MWH	1	2	2	$31.59	$27.50	$32.36	$28.17	0	0	0	0	0	0	0	2.4%
Riders		MWH	1	2	2	$5.88	$5.88	$1.31	$1.31	0	0	0	0	0	0	0	-77.7%
Total:										3	5	8	3	6	9	1	12.4%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units Summer	Billing Units Winter	Billing Units Annual	Present Rate Summer	Present Rate Winter	Proposed Rate Summer	Proposed Rate Winter	Present Revenues Summer	Present Revenues Winter	Present Revenues Annual	Proposed Revenues Summer	Proposed Revenues Winter	Proposed Revenues Annual	Increase Annual	Pct Inc. Annual
A12 SmallGen TOD Sm C&I Secondary																	
Cust Chg		Bills	11,733	23,451	35,184	$12.78	$12.78	$14.23	$14.23	150	300	450	167	334	501	51	11.4%
Energy	On	MWH	3,538	9,017	12,555	$148.80	$117.23	$185.54	$149.84	526	1,057	1,584	656	1,351	2,008	424	26.8%
Energy	Off	MWH	7,248	18,646	25,895	$41.70	$41.70	$56.24	$56.24	302	778	1,080	408	1,049	1,456	377	34.9%
SvrSwtchAC		Tons	766	0	766	-$5.00	$0.00	-$5.00	$0.00	-4	0	-4	-4	0	-4	0	0.0%
Fuel Cost		MWH	10,786	27,664	38,450	$31.59	$27.50	$32.36	$28.17	341	761	1,101	349	779	1,128	27	2.4%
Riders		MWH	10,786	27,664	38,450	$5.88	$5.88	$1.31	$1.31	63	163	226	14	36	50	-176	-77.7%
Total:										1,379	3,058	4,437	1,590	3,549	5,139	703	15.8%
A16 SGS TOD kWh Mtr Sm C&I Secondary																	
Cust Chg		Bills	12,359	24,705	37,064	$10.78	$10.78	$12.23	$12.23	133	266	400	151	302	453	54	13.5%
Energy		MWH	4,367	9,649	14,016	$79.19	$68.14	$101.50	$89.00	346	657	1,003	443	859	1,302	299	29.8%
Fuel Cost		MWH	4,367	9,649	14,016	$31.59	$27.50	$32.36	$28.17	138	265	403	141	272	413	10	2.4%
Riders		MWH	4,367	9,649	14,016	$5.88	$5.88	$1.31	$1.31	26	57	82	6	13	18	-64	-77.7%
Total:										643	1,246	1,889	741	1,445	2,187	298	15.8%
A18 SGS TOD UnMtrd Sm C&I Secondary																	
Cust Chg		Bills	17,557	35,093	52,650	$8.78	$8.78	$10.23	$10.23	154	308	462	180	359	539	76	16.5%
Energy		MWH	8,569	17,558	26,127	$79.19	$68.14	$101.50	$89.00	679	1,196	1,875	870	1,563	2,432	557	29.7%
Fuel Cost		MWH	8,569	17,558	26,127	$31.59	$27.50	$32.36	$28.17	271	483	753	277	495	772	18	2.4%
Riders		MWH	8,569	17,558	26,127	$5.88	$5.88	$1.31	$1.31	50	103	154	11	23	34	-119	-77.7%
Total:										1,154	2,091	3,244	1,338	2,439	3,777	533	16.4%
A22 SGS TOD Low Watt Sm C&I Secondary																	
Cust Chg		Bills	2,991	5,979	8,970	$0.00	$0.00	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
LwWattSm		Bills	72,592	145,184	217,776	$0.30	$0.30	$0.34	$0.34	22	44	65	25	49	74	9	13.3%
LwWattLg		Bills	168	336	504	$1.20	$1.20	$1.32	$1.32	0	0	1	0	0	1	0	10.0%
Energy		MWH	734	1,492	2,225	$79.19	$68.14	$101.50	$89.00	58	102	160	74	133	207	47	29.7%
Fuel Cost		MWH	734	1,492	2,225	$31.59	$27.50	$32.36	$28.17	23	41	64	24	42	66	2	2.4%
Riders		MWH	734	1,492	2,225	$5.88	$5.88	$1.31	$1.31	4	9	13	1	2	3	-10	-77.7%
Total:										108	195	303	124	227	351	48	15.7%
A14 General Sm C&I Secondary																	
Cust Chg		Bills	167,552	334,912	502,464	$27.98	$27.98	$28.72	$28.72	4,688	9,371	14,059	4,812	9,619	14,431	372	2.6%
Energy		MWH	2,619,644	4,760,504	7,380,148	$34.07	$34.07	$44.30	$44.30	89,251	162,190	251,442	116,050	210,890	326,941	75,499	30.0%
Energy Cr		MWH	122,981	275,069	398,050	-$15.18	-$15.18	-$18.68	-$18.68	-1,867	-4,176	-6,042	-2,297	-5,138	-7,436	-1,393	23.1%
SvrSwtchAC		Tons	435,935	0	435,935	-$5.00	$0.00	-$5.00	$0.00	-2,180	0	-2,180	-2,180	0	-2,180	0	0.0%
Demand		KW	8,319,020	14,669,717	22,988,737	$14.79	$10.49	$17.54	$12.93	123,038	153,885	276,924	145,916	189,679	335,595	58,671	21.2%
BIS Rdr		KW	1,535	3,793	5,328	-$5.92	-$4.20	-$7.02	-$5.17	-9	-16	-25	-11	-20	-30	-5	21.6%
Fuel Cost		MWH	2,619,644	4,760,504	7,380,148	$28.09	$28.09	$28.16	$28.16	73,592	133,733	207,325	73,778	134,072	207,851	526	0.3%
Riders		KW	8,319,020	14,669,717	22,988,737	$0.99	$0.99	$0.00	$0.00	8,265	14,575	22,840	0	0	0	-22,840	-100.0%
Riders		MWH	2,619,644	4,760,504	7,380,148	$2.47	$2.47	$1.31	$1.31	6,462	11,742	18,204	3,437	6,245	9,682	-8,522	-46.8%
Total:										301,240	481,305	782,545	339,505	545,348	884,853	102,308	13.1%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
		Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A14 General Lg C&I Secondary																
Cust Chg	Bills	168	336	504	$27.98	$27.98	$28.72	$28.72	5	9	14	5	10	14	0	2.6%
Energy	MWH	47,052	88,056	135,108	$34.07	$34.07	$44.30	$44.30	1,603	3,000	4,603	2,084	3,901	5,985	1,382	30.0%
Energy Cr	MWH	4,780	8,930	13,710	-$15.18	-$15.18	-$18.68	-$18.68	-73	-136	-208	-89	-167	-256	-48	23.1%
SvrSwtchAC	Tons	293,332	0	293,332	-$5.00	$0.00	-$5.00	$0.00	-1,467	0	-1,467	-1,467	0	-1,467	0	0.0%
Demand	KW	126,125	231,733	357,858	$14.79	$10.49	$17.54	$12.93	1,865	2,431	4,296	2,212	2,996	5,209	912	21.2%
Fuel Cost	MWH	47,052	88,056	135,108	$28.09	$28.09	$28.16	$28.16	1,322	2,474	3,795	1,325	2,480	3,805	10	0.3%
Riders	KW	126,125	231,733	357,858	$0.99	$0.99	$0.00	$0.00	125	230	356	0	0	0	-356	-100.0%
Riders	MWH	47,052	88,056	135,108	$2.47	$2.47	$1.31	$1.31	116	217	333	62	116	177	-156	-46.8%
Total:									3,497	8,226	11,723	4,132	9,336	13,468	1,745	14.9%
A41 Municipal Pumping Public Auth Secondary																
Cust Chg	Bills	2,268	4,531	6,799	$27.98	$27.98	$28.72	$28.72	63	127	190	65	130	195	5	2.6%
Energy	MWH	24,430	34,477	58,907	$34.07	$34.07	$44.30	$44.30	832	1,175	2,007	1,082	1,527	2,610	603	30.0%
Energy Cr	MWH	1,925	1,898	3,823	-$15.18	-$15.18	-$18.68	-$18.68	-29	-29	-58	-36	-35	-71	-13	23.1%
Demand	KW	96,658	148,254	244,912	$14.79	$10.49	$17.54	$12.93	1,430	1,555	2,985	1,695	1,917	3,612	628	21.0%
Fuel Cost	MWH	24,430	34,477	58,907	$28.09	$28.09	$28.16	$28.16	686	969	1,655	688	971	1,659	4	0.3%
Riders	KW	96,658	148,254	244,912	$0.99	$0.99	$0.00	$0.00	96	147	243	0	0	0	-243	-100.0%
Riders	MWH	24,430	34,477	58,907	$2.47	$2.47	$1.31	$1.31	60	85	145	32	45	77	-68	-46.8%
Total:									3,139	4,029	7,167	3,527	4,555	8,082	915	12.8%
A14 General Sm C&I Primary																
Cust Chg	Bills	520	1,040	1,560	$27.98	$27.98	$28.72	$28.72	15	29	44	15	30	45	1	2.6%
Energy	MWH	38,010	71,200	109,210	$33.02	$33.02	$43.06	$43.06	1,255	2,351	3,606	1,637	3,066	4,703	1,096	30.4%
Energy Cr	MWH	1,479	4,488	5,967	-$15.18	-$15.18	-$18.68	-$18.68	-22	-68	-91	-28	-84	-111	-21	23.1%
SvrSwtchAC	Tons	3,108	0	3,108	-$5.00	$0.00	-$5.00	$0.00	-16	0	-16	-16	0	-16	0	0.0%
Demand	KW	120,641	206,132	326,773	$13.99	$9.69	$16.94	$12.33	1,688	1,997	3,685	2,044	2,542	4,585	900	24.4%
Fuel Cost	MWH	38,010	71,200	109,210	$28.09	$28.09	$28.16	$28.16	1,068	2,000	3,068	1,070	2,005	3,076	8	0.3%
Riders	KW	120,641	206,132	326,773	$0.99	$0.99	$0.00	$0.00	120	205	325	0	0	0	-325	-100.0%
Riders	MWH	38,010	71,200	109,210	$2.47	$2.47	$1.31	$1.31	94	176	269	50	93	143	-126	-46.8%
Total:									4,201	6,690	10,891	4,772	7,652	12,425	1,534	14.1%
A14 General Lg C&I Primary																
Cust Chg	Bills	16	32	48	$27.98	$27.98	$28.72	$28.72	0	1	1	0	1	1	0	2.6%
Energy	MWH	7,227	8,875	16,102	$33.02	$33.02	$43.06	$43.06	239	293	532	311	382	693	162	30.4%
Energy Cr	MWH	370	910	1,280	-$15.18	-$15.18	-$18.68	-$18.68	-6	-14	-19	-7	-17	-24	-4	23.1%
SvrSwtchAC	Tons	0	0	0	-$5.00	$0.00	-$5.00	$0.00	0	0	0	0	0	0	0	0.0%
Demand	KW	25,415	29,726	55,141	$13.99	$9.69	$16.94	$12.33	356	288	644	431	367	797	153	23.8%
Fuel Cost	MWH	7,227	8,875	16,102	$28.09	$28.09	$28.16	$28.16	203	249	452	204	250	453	1	0.3%
Riders	KW	25,415	29,726	55,141	$0.99	$0.99	$0.00	$0.00	25	30	55	0	0	0	-55	-100.0%
Riders	MWH	7,227	8,875	16,102	$2.47	$2.47	$1.31	$1.31	18	22	40	9	12	21	-19	-46.8%
Total:									835	869	1,704	948	994	1,942	238	14.0%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
		Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A41 Municipal Pumping Public Auth Primary																
Cust Chg	Bills	32	64	96	$27.98	$27.98	$28.72	$28.72	1	2	3	1	2	3	0	2.6%
Energy	MWH	551	902	1,453	$33.02	$33.02	$43.06	$43.06	18	30	48	24	39	63	15	30.4%
Energy Cr	MWH	3	7	10	-$15.18	-$15.18	-$18.68	-$18.68	0	0	0	0	0	0	0	23.1%
Demand	KW	2,531	4,421	6,952	$13.99	$9.69	$16.94	$12.33	35	43	78	43	55	97	19	24.5%
Fuel Cost	MWH	551	902	1,453	$28.09	$28.09	$28.16	$28.16	15	25	41	16	25	41	0	0.3%
Riders	KW	2,531	4,421	6,952	$0.99	$0.99	$0.00	$0.00	3	4	7	0	0	0	-7	-100.0%
Riders	MWH	551	902	1,453	$2.47	$2.47	$1.31	$1.31	1	2	4	1	1	2	-2	-46.8%
Total:									74	106	180	84	122	205	25	14.0%
A14 General Sm C&I Tr Transformed																
Cust Chg	Bills	4	8	12	$27.98	$27.98	$28.72	$28.72	0	0	0	0	0	0	0	2.6%
Energy	MWH	380	3,757	4,137	$31.40	$31.40	$41.25	$41.25	12	118	130	16	155	171	41	31.4%
Energy Cr	MWH	0	0	0	-$15.18	-$15.18	-$18.68	-$18.68	0	0	0	0	0	0	0	0.0%
Demand	KW	0	13,066	13,066	$13.24	$8.94	$15.54	$10.93	0	117	117	0	143	143	26	22.3%
Fuel Cost	MWH	380	3,757	4,137	$28.09	$28.09	$28.16	$28.16	11	106	116	11	106	117	0	0.3%
Riders	KW	0	13,066	13,066	$0.99	$0.99	$0.00	$0.00	0	13	13	0	0	0	-13	-100.0%
Riders	MWH	380	3,757	4,137	$2.47	$2.47	$1.31	$1.31	1	9	10	0	5	5	-5	-46.8%
Total:									24	363	386	27	409	436	49	12.8%
A14 General Lg C&I Tr Transformed																
Cust Chg	Bills	0	0	0	$27.98	$27.98	$28.72	$28.72	0	0	0	0	0	0	0	0.0%
Energy	MWH	0	0	0	$31.40	$31.40	$41.25	$41.25	0	0	0	0	0	0	0	0.0%
Energy Cr	MWH	0	0	0	-$15.18	-$15.18	-$18.68	-$18.68	0	0	0	0	0	0	0	0.0%
Demand	KW	0	0	0	$13.24	$8.94	$15.54	$10.93	0	0	0	0	0	0	0	0.0%
Fuel Cost	MWH	0	0	0	$28.09	$28.09	$28.16	$28.16	0	0	0	0	0	0	0	0.0%
Riders	KW	0	0	0	$0.99	$0.99	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Riders	MWH	0	0	0	$2.47	$2.47	$1.31	$1.31	0	0	0	0	0	0	0	0.0%
Total:									0	0	0	0	0	0	0	0.0%
A14 General Sm C&I Transmission																
Cust Chg	Bills	4	8	12	$27.98	$27.98	$28.72	$28.72	0	0	0	0	0	0	0	2.6%
Energy	MWH	23	45	67	$31.30	$31.30	$41.14	$41.14	1	1	2	1	2	3	1	31.4%
Energy Cr	MWH	0	0	0	-$15.18	-$15.18	-$18.68	-$18.68	0	0	0	0	0	0	0	0.0%
Demand	KW	216	411	628	$12.44	$8.14	$14.54	$9.93	3	3	6	3	4	7	1	19.7%
Fuel Cost	MWH	23	45	67	$28.09	$28.09	$28.16	$28.16	1	1	2	1	1	2	0	0.3%
Riders	KW	216	411	628	$0.99	$0.99	$0.00	$0.00	0	0	1	0	0	0	-1	-100.0%
Riders	MWH	23	45	67	$2.47	$2.47	$1.31	$1.31	0	0	0	0	0	0	0	-46.8%
Total:									4	7	11	5	7	12	1	10.4%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A15 General TOD Sm C&I Secondary																	
Cust Chg		Bills	17,634	35,246	52,880	$31.98	$31.98	$32.72	$32.72	564	1,127	1,691	577	1,153	1,730	39	2.3%
Energy	On	MWH	332,949	574,107	907,057	$48.55	$48.55	$62.96	$62.96	16,165	27,873	44,038	20,962	36,146	57,108	13,071	29.7%
Energy	Off	MWH	522,077	930,552	1,452,628	$23.41	$23.41	$30.71	$30.71	12,222	21,784	34,006	16,033	28,577	44,610	10,604	31.2%
Energy Cr		MWH	144,580	280,201	424,781	-$15.18	-$15.18	-$18.68	-$18.68	-2,195	-4,253	-6,448	-2,701	-5,234	-7,935	-1,487	23.1%
SvrSwtchAC		Tons	30,147	0	30,147	-$5.00	$0.00	-$5.00	$0.00	-151	0	-151	-151	0	-151	0	0.0%
Demand		KW	1,866,653	3,197,249	5,063,902	$14.79	$10.49	$17.54	$12.93	27,608	33,539	61,147	32,741	41,340	74,082	12,935	21.2%
Off Dmd		KW	50,539	112,513	163,053	$2.35	$2.35	$3.00	$3.00	119	264	383	152	338	489	106	27.7%
BIS Rdr		KW	0	0	0	-$5.92	-$4.20	-$7.02	-$5.17	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	332,949	574,107	907,057	$35.13	$35.13	$35.20	$35.20	11,697	20,170	31,867	11,719	20,208	31,927	60	0.2%
Fuel Cost	Off	MWH	522,077	930,552	1,452,628	$22.98	$22.98	$23.04	$23.04	11,996	21,381	33,377	12,027	21,437	33,464	87	0.3%
Riders		KW	1,866,653	3,197,249	5,063,902	$0.99	$0.99	$0.00	$0.00	1,855	3,177	5,031	0	0	0	-5,031	-100.0%
Riders		MWH	855,026	1,504,659	2,359,685	$2.47	$2.47	$1.31	$1.31	2,109	3,711	5,820	1,122	1,974	3,096	-2,725	-46.8%
Total:										81,988	128,773	210,761	92,482	145,939	238,420	27,659	13.1%
A15 General TOD Lg C&I Secondary																	
Cust Chg		Bills	804	1,608	2,412	$31.98	$31.98	$32.72	$32.72	26	51	77	26	53	79	2	2.3%
Energy	On	MWH	255,218	431,700	686,919	$48.55	$48.55	$62.96	$62.96	12,391	20,959	33,350	16,069	27,180	43,248	9,899	29.7%
Energy	Off	MWH	368,265	639,419	1,007,684	$23.41	$23.41	$30.71	$30.71	8,621	14,969	23,590	11,309	19,637	30,946	7,356	31.2%
Energy Cr		MWH	104,590	190,682	295,272	-$15.18	-$15.18	-$18.68	-$18.68	-1,588	-2,895	-4,482	-1,954	-3,562	-5,516	-1,033	23.1%
SvrSwtchAC		Tons	76,974	0	76,974	-$5.00	$0.00	-$5.00	$0.00	-385	0	-385	-385	0	-385	0	0.0%
Demand		KW	1,355,202	2,268,411	3,623,613	$14.79	$10.49	$17.54	$12.93	20,043	23,796	43,839	23,770	29,331	53,101	9,262	21.1%
Off Dmd		KW	16,018	48,261	64,280	$2.35	$2.35	$3.00	$3.00	38	113	151	48	145	193	42	27.7%
BIS Rdr		KW	14,631	30,240	44,871	-$5.92	-$4.20	-$7.02	-$5.17	-87	-127	-213	-103	-156	-259	-46	21.4%
AreaDevRdr		KW	0	0	0	-$2.96	-$2.10	-$3.51	-$2.59	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	255,218	431,700	686,919	$35.13	$35.13	$35.20	$35.20	8,966	15,167	24,133	8,983	15,195	24,179	46	0.2%
Fuel Cost	Off	MWH	368,265	639,419	1,007,684	$22.98	$22.98	$23.04	$23.04	8,462	14,692	23,153	8,484	14,730	23,214	60	0.3%
Riders		KW	1,355,202	2,268,411	3,623,613	$0.99	$0.99	$0.00	$0.00	1,346	2,254	3,600	0	0	0	-3,600	-100.0%
Riders		MWH	623,483	1,071,119	1,694,603	$2.47	$2.47	$1.31	$1.31	1,538	2,642	4,180	818	1,405	2,223	-1,957	-46.8%
Total:										59,372	91,621	150,993	67,066	103,957	171,023	20,030	13.3%
A15 General TOD Sm C&I Primary																	
Cust Chg		Bills	304	608	912	$31.98	$31.98	$32.72	$32.72	10	19	29	10	20	30	1	2.3%
Energy	On	MWH	20,961	33,326	54,287	$47.50	$47.50	$61.72	$61.72	996	1,583	2,579	1,294	2,057	3,351	772	29.9%
Energy	Off	MWH	32,155	52,624	84,778	$22.36	$22.36	$29.47	$29.47	719	1,177	1,896	948	1,551	2,498	603	31.8%
Energy Cr		MWH	9,488	14,070	23,558	-$15.18	-$15.18	-$18.68	-$18.68	-144	-214	-358	-177	-263	-440	-82	23.1%
SvrSwtchAC		Tons	2,643	0	2,643	-$5.00	$0.00	-$5.00	$0.00	-13	0	-13	-13	0	-13	0	0.0%
Demand		KW	121,648	199,170	320,818	$13.99	$9.69	$16.94	$12.33	1,702	1,930	3,632	2,061	2,456	4,516	885	24.4%
Off Dmd		KW	8,904	12,543	21,448	$1.55	$1.55	$2.40	$2.40	14	19	33	21	30	51	18	54.8%
BIS Rdr		KW	0	0	0	-$5.60	-$3.88	-$6.78	-$4.93	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	20,961	33,326	54,287	$35.13	$35.13	$35.20	$35.20	736	1,171	1,907	738	1,173	1,911	4	0.2%
Fuel Cost	Off	MWH	32,155	52,624	84,778	$22.98	$22.98	$23.04	$23.04	739	1,209	1,948	741	1,212	1,953	5	0.3%
Riders		KW	121,648	199,170	320,818	$0.99	$0.99	$0.00	$0.00	121	198	319	0	0	0	-319	-100.0%
Riders		MWH	53,116	85,949	139,065	$2.47	$2.47	$1.31	$1.31	131	212	343	70	113	182	-161	-46.8%
Total:										5,010	7,305	12,315	5,691	8,349	14,040	1,725	14.0%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A15 General TOD Lg C&I Primary																	
Cust Chg		Bills	404	808	1,212	$31.98	$31.98	$32.72	$32.72	13	26	39	13	26	40	1	2.3%
Energy		MWH	292,465	467,237	759,702	$47.50	$47.50	$61.72	$61.72	13,892	22,194	36,087	18,051	28,838	46,889	10,802	29.9%
Energy	On	MWH	448,988	743,368	1,192,356	$22.36	$22.36	$29.47	$29.47	10,040	16,622	26,662	13,232	21,907	35,139	8,476	31.8%
Energy Cr	Off	MWH	148,285	264,387	412,672	-$15.18	-$15.18	-$18.68	-$18.68	-2,251	-4,013	-6,264	-2,770	-4,939	-7,709	-1,444	23.1%
SvrSwtchAC		Tons	2,724	0	2,724	-$5.00	$0.00	-$5.00	$0.00	-14	0	-14	-14	0	-14	0	0.0%
Demand		KW	1,527,796	2,451,874	3,979,670	$13.99	$9.69	$16.94	$12.33	21,374	23,759	45,133	25,881	30,232	56,112	10,980	24.3%
Off Dmd		KW	29,553	89,299	118,853	$1.55	$1.55	$2.40	$2.40	46	138	184	71	214	285	101	54.8%
BIS Rdr		KW	9,200	19,889	29,089	-$5.60	-$3.88	-$6.78	-$4.93	-51	-77	-129	-62	-98	-160	-32	24.8%
Fuel Cost	On	MWH	292,465	467,237	759,702	$35.13	$35.13	$35.20	$35.20	10,275	16,415	26,690	10,294	16,446	26,741	51	0.2%
Fuel Cost	Off	MWH	448,988	743,368	1,192,356	$22.98	$22.98	$23.04	$23.04	10,316	17,080	27,397	10,343	17,125	27,468	71	0.3%
Riders		KW	1,527,796	2,451,874	3,979,670	$0.99	$0.99	$0.00	$0.00	1,518	2,436	3,954	0	0	0	-3,954	-100.0%
Riders		MWH	741,453	1,210,605	1,952,058	$2.47	$2.47	$1.31	$1.31	1,829	2,986	4,815	973	1,588	2,561	-2,254	-46.8%
Total:										66,987	97,566	164,553	76,012	111,340	187,352	22,798	13.9%
A29 Light Rail Sm C&I Primary																	
Cust Chg		Bills	64	128	192	$102.34	$102.34	$101.72	$101.72	7	13	20	7	13	20	0	-0.6%
Energy	On	MWH	3,139	7,038	10,177	$47.50	$47.50	$61.72	$61.72	149	334	483	194	434	628	145	29.9%
Energy	Off	MWH	3,774	9,663	13,436	$22.36	$22.36	$29.47	$29.47	84	216	300	111	285	396	96	31.8%
Energy Cr		MWH	1,270	2,816	4,086	-$13.03	-$13.03	-$16.00	-$16.00	-17	-37	-53	-20	-45	-65	-12	22.8%
Demand		KW	14,366	35,623	49,989	$8.71	$4.41	$9.60	$4.99	125	157	282	138	178	316	33	11.9%
Trans Dmd		KW	20,279	48,901	69,180	$5.28	$5.28	$7.34	$7.34	107	258	365	149	359	508	143	39.0%
Off Dmd		KW	1,319	2,501	3,820	$1.55	$1.55	$2.40	$2.40	2	4	6	3	6	9	3	54.8%
Fuel Cost	On	MWH	3,139	7,038	10,177	$35.13	$35.13	$35.20	$35.20	110	247	358	110	248	358	1	0.2%
Fuel Cost	Off	MWH	3,774	9,663	13,436	$22.98	$22.98	$23.04	$23.04	87	222	309	87	223	310	1	0.3%
Riders		KW	20,279	48,901	69,180	$0.99	$0.99	$0.00	$0.00	20	49	69	0	0	0	-69	-100.0%
Riders		MWH	6,913	16,701	23,614	$2.47	$2.47	$1.31	$1.31	17	41	58	9	22	31	-27	-46.8%
Total:										692	1,505	2,197	788	1,722	2,510	313	14.2%
A15 General TOD Sm C&I Transmission																	
Cust Chg		Bills	4	8	12	$31.98	$31.98	$32.72	$32.72	0	0	0	0	0	0	0	2.3%
Energy	On	MWH	37	76	113	$45.78	$45.78	$59.80	$59.80	2	3	5	2	5	7	2	30.6%
Energy	Off	MWH	0	0	0	$20.64	$20.64	$27.55	$27.55	0	0	0	0	0	0	0	0.0%
Energy Cr		MWH	9	14	24	-$15.18	-$15.18	-$18.68	-$18.68	0	0	0	0	0	0	0	23.1%
SvrSwtchAC		Tons	0	0	0	-$5.00	$0.00	-$5.00	$0.00	0	0	0	0	0	0	0	0.0%
Demand		KW	203	889	1,092	$12.44	$8.14	$14.54	$9.93	3	7	10	3	9	12	2	20.7%
Off Dmd		KW	0	0	0	$0.00	$0.00	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	37	76	113	$35.13	$35.13	$35.20	$35.20	1	3	4	1	3	4	0	0.2%
Fuel Cost	Off	MWH	0	0	0	$22.98	$22.98	$23.04	$23.04	0	0	0	0	0	0	0	0.0%
Riders		KW	203	889	1,092	$0.99	$0.99	$0.00	$0.00	0	1	1	0	0	0	-1	-100.0%
Riders		MWH	37	76	113	$2.47	$2.47	$1.31	$1.31	0	0	0	0	0	0	0	-46.8%
Total:										6	15	20	7	16	23	2	11.4%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units Summer	Billing Units Winter	Billing Units Annual	Present Rate Summer	Present Rate Winter	Proposed Rate Summer	Proposed Rate Winter	Present Revenues Summer	Present Revenues Winter	Present Revenues Annual	Proposed Revenues Summer	Proposed Revenues Winter	Proposed Revenues Annual	Increase Annual	Pct Inc. Annual
A15 General TOD Lg C&I Tr Transformed																	
Cust Chg		Bills	24	48	72	$31.98	$31.98	$32.72	$32.72	1	2	2	1	2	2	0	2.3%
Energy	On	MWH	154,579	249,959	404,538	$45.88	$45.88	$59.91	$59.91	7,092	11,468	18,560	9,261	14,975	24,236	5,676	30.6%
Energy	Off	MWH	258,963	439,092	698,055	$20.74	$20.74	$27.66	$27.66	5,371	9,107	14,478	7,163	12,146	19,309	4,831	33.4%
Energy Cr		MWH	156,755	266,251	423,007	-$15.18	-$15.18	-$18.68	-$18.68	-2,380	-4,042	-6,421	-2,928	-4,974	-7,902	-1,481	23.1%
SvrSwtchAC		Tons	752	0	752	-$5.00	$0.00	-$5.00	$0.00	-4	0	-4	-4	0	-4	0	0.0%
Demand		KW	672,093	1,083,355	1,755,448	$13.24	$8.94	$15.54	$10.93	8,899	9,685	18,584	10,444	11,841	22,285	3,702	19.9%
Off Dmd		KW	1,064	8,456	9,520	$0.80	$0.80	$1.00	$1.00	1	7	8	1	8	10	2	25.0%
Fuel Cost	On	MWH	154,579	249,959	404,538	$35.13	$35.13	$35.20	$35.20	5,431	8,782	14,212	5,441	8,798	14,239	27	0.2%
Fuel Cost	Off	MWH	258,963	439,092	698,055	$22.98	$22.98	$23.04	$23.04	5,950	10,089	16,039	5,966	10,115	16,081	42	0.3%
Riders		KW	672,093	1,083,355	1,755,448	$0.99	$0.99	$0.00	$0.00	668	1,076	1,744	0	0	0	-1,744	-100.0%
Riders		MWH	413,542	689,051	1,102,593	$2.47	$2.47	$1.31	$1.31	1,020	1,700	2,720	543	904	1,446	-1,273	-46.8%
Total:										32,048	47,873	79,922	35,888	53,816	89,704	9,782	12.2%
A15 General TOD Lg C&I Transmission																	
Cust Chg		Bills	12	24	36	$31.98	$31.98	$32.72	$32.72	0	1	1	0	1	1	0	2.3%
Energy	On	MWH	20,108	39,315	59,422	$45.78	$45.78	$59.80	$59.80	921	1,800	2,720	1,202	2,351	3,554	833	30.6%
Energy	Off	MWH	36,277	68,314	104,592	$20.64	$20.64	$27.55	$27.55	749	1,410	2,159	1,000	1,882	2,882	723	33.5%
Energy Cr		MWH	0	814	814	-$15.18	-$15.18	-$18.68	-$18.68	0	-12	-12	0	-15	-15	-3	23.1%
Demand		KW	161,860	260,112	421,972	$12.44	$8.14	$14.54	$9.93	2,014	2,117	4,131	2,353	2,583	4,936	806	19.5%
Off Dmd		KW	0	0	0	$0.00	$0.00	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	20,108	39,315	59,422	$35.13	$35.13	$35.20	$35.20	706	1,381	2,088	708	1,384	2,092	4	0.2%
Fuel Cost	Off	MWH	36,277	68,314	104,592	$22.98	$22.98	$23.04	$23.04	834	1,570	2,403	836	1,574	2,409	6	0.3%
Riders		KW	161,860	260,112	421,972	$0.99	$0.99	$0.00	$0.00	161	258	419	0	0	0	-419	-100.0%
Riders		MWH	56,385	107,629	164,014	$2.47	$2.47	$1.31	$1.31	139	265	405	74	141	215	-189	-46.8%
Total:										5,523	8,790	14,313	6,173	9,901	16,074	1,760	12.3%
A23 Peak-Ctrl Tier Sm C&I Secondary																	
Cust Chg		Bills	5,494	10,982	16,476	$57.34	$57.34	$61.72	$61.72	315	630	945	339	678	1,017	72	7.6%
Energy		MWH	338,161	646,587	984,748	$34.07	$34.07	$44.30	$44.30	11,521	22,029	33,550	14,981	28,644	43,624	10,074	30.0%
Energy Cr		MWH	11,388	22,080	33,468	-$15.18	-$15.18	-$18.68	-$18.68	-173	-335	-508	-213	-412	-625	-117	23.1%
Demand		KW	506,421	992,104	1,498,525	$14.79	$10.49	$17.54	$12.93	7,490	10,407	17,897	8,883	12,828	21,711	3,813	21.3%
Control Dmd		KW	316,508	498,895	815,403	$8.88	$8.88	$11.36	$11.36	2,811	4,430	7,241	3,596	5,667	9,263	2,022	27.9%
Control Dmd		KW	214,277	333,426	547,703	$7.86	$7.86	$10.21	$10.21	1,684	2,621	4,305	2,188	3,404	5,592	1,287	29.9%
Control Dmd		KW	177,845	310,732	488,577	$7.34	$7.34	$9.67	$9.67	1,305	2,281	3,586	1,720	3,005	4,725	1,138	31.7%
Control Dmd		KW	10,825	19,370	30,196	$7.15	$7.15	$9.47	$9.47	77	138	216	103	183	286	70	32.4%
Control Dmd		KW	41,571	76,433	118,004	$6.56	$6.56	$8.85	$8.85	273	501	774	368	676	1,044	270	34.9%
Control Dmd		KW	2,539	5,827	8,366	$6.09	$6.09	$8.35	$8.35	15	35	51	21	49	70	19	37.1%
AnnMinDmd		KW	39,935	79,870	119,805	$1.00	$1.00	$1.32	$1.32	40	80	120	53	105	158	38	32.0%
Fuel Cost		MWH	338,161	646,587	984,748	$28.09	$28.09	$28.16	$28.16	9,500	18,164	27,664	9,524	18,210	27,734	70	0.3%
Riders		KW	1,269,986	2,236,787	3,506,774	$0.99	$0.99	$0.00	$0.00	1,262	2,222	3,484	0	0	0	-3,484	-100.0%
Riders		MWH	338,161	646,587	984,748	$2.47	$2.47	$1.31	$1.31	834	1,595	2,429	444	848	1,292	-1,137	-46.8%
Total:										36,955	64,799	101,754	42,004	73,886	115,890	14,137	13.9%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
		Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A23 Peak-Ctrl Tier Lg C&I Secondary																
Cust Chg	Bills	16	32	48	$57.34	$57.34	$61.72	$61.72	1	2	3	1	2	3	0	7.6%
Energy	MWH	5,176	8,696	13,872	$34.07	$34.07	$44.30	$44.30	176	296	473	229	385	615	142	30.0%
Energy Cr	MWH	464	868	1,332	-$15.18	-$15.18	-$18.68	-$18.68	-7	-13	-20	-9	-16	-25	-5	23.1%
Demand	KW	2,926	4,526	7,452	$14.79	$10.49	$17.54	$12.93	43	47	91	51	59	110	19	21.0%
Control Dmd	KW	3,333	4,478	7,811	$8.88	$8.88	$11.36	$11.36	30	40	69	38	51	89	19	27.9%
Control Dmd	KW	3,265	4,136	7,400	$7.86	$7.86	$10.21	$10.21	26	33	58	33	42	76	17	29.9%
Control Dmd	KW	6,434	10,486	16,919	$7.34	$7.34	$9.67	$9.67	47	77	124	62	101	164	39	31.7%
Control Dmd	KW	0	0	0	$7.15	$7.15	$9.47	$9.47	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	664	1,087	1,750	$6.56	$6.56	$8.85	$8.85	4	7	11	6	10	15	4	34.9%
Control Dmd	KW	0	0	0	$6.09	$6.09	$8.35	$8.35	0	0	0	0	0	0	0	0.0%
Fuel Cost	MWH	5,176	8,696	13,872	$28.09	$28.09	$28.16	$28.16	145	244	390	146	245	391	1	0.3%
Riders	KW	16,621	24,712	41,333	$0.99	$0.99	$0.00	$0.00	17	25	41	0	0	0	-41	-100.0%
Riders	MWH	5,176	8,696	13,872	$2.47	$2.47	$1.31	$1.31	13	21	34	7	11	18	-16	-46.8%
Total:									495	779	1,274	565	890	1,455	181	14.2%
A23 Peak-Ctrl Tier Sm C&I Primary																
Cust Chg	Bills	184	368	552	$57.34	$57.34	$61.72	$61.72	11	21	32	11	23	34	2	7.6%
Energy	MWH	21,744	45,260	67,003	$33.02	$33.02	$43.06	$43.06	718	1,495	2,213	936	1,949	2,885	673	30.4%
Energy Cr	MWH	506	1,604	2,110	-$15.18	-$15.18	-$18.68	-$18.68	-8	-24	-32	-9	-30	-39	-7	23.1%
Demand	KW	27,876	58,382	86,258	$13.99	$9.69	$16.94	$12.33	390	566	956	472	720	1,192	236	24.7%
Control Dmd	KW	25,372	43,809	69,180	$8.08	$8.08	$10.76	$10.76	205	354	559	273	471	744	185	33.2%
Control Dmd	KW	9,123	17,279	26,402	$7.06	$7.06	$9.61	$9.61	64	122	186	88	166	254	67	36.1%
Control Dmd	KW	13,354	16,188	29,541	$6.54	$6.54	$9.07	$9.07	87	106	193	121	147	268	75	38.7%
Control Dmd	KW	3,025	5,684	8,708	$6.35	$6.35	$8.87	$8.87	19	36	55	27	50	77	22	39.7%
Control Dmd	KW	1,962	5,626	7,588	$5.76	$5.76	$8.25	$8.25	11	32	44	16	46	63	19	43.2%
Control Dmd	KW	2,891	5,560	8,451	$5.29	$5.29	$7.75	$7.75	15	29	45	22	43	65	21	46.5%
Fuel Cost	MWH	21,744	45,260	67,003	$28.09	$28.09	$28.16	$28.16	611	1,271	1,882	612	1,275	1,887	5	0.3%
Riders	KW	83,602	152,526	236,129	$0.99	$0.99	$0.00	$0.00	83	152	235	0	0	0	-235	-100.0%
Riders	MWH	21,744	45,260	67,003	$2.47	$2.47	$1.31	$1.31	54	112	165	29	59	88	-77	-46.8%
Total:									2,261	4,271	6,532	2,599	4,920	7,518	986	15.1%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
		Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A23 Peak-Ctrl Tier Lg C&I Primary																
Cust Chg	Bills	0	0	0	$57.34	$57.34	$61.72	$61.72	0	0	0	0	0	0	0	0.0%
Energy	MWH	0	0	0	$33.02	$33.02	$43.06	$43.06	0	0	0	0	0	0	0	0.0%
Energy Cr	MWH	0	0	0	-$15.18	-$15.18	-$18.68	-$18.68	0	0	0	0	0	0	0	0.0%
Demand	KW	0	0	0	$13.99	$9.69	$16.94	$12.33	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$8.08	$8.08	$10.76	$10.76	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$7.06	$7.06	$9.61	$9.61	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$6.54	$6.54	$9.07	$9.07	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$6.35	$6.35	$8.87	$8.87	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$5.76	$5.76	$8.25	$8.25	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$5.29	$5.29	$7.75	$7.75	0	0	0	0	0	0	0	0.0%
Fuel Cost	MWH	0	0	0	$28.09	$28.09	$28.16	$28.16	0	0	0	0	0	0	0	0.0%
Riders	KW	0	0	0	$0.99	$0.99	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Riders	MWH	0	0	0	$2.47	$2.47	$1.31	$1.31	0	0	0	0	0	0	0	0.0%
Total:									0	0	0	0	0	0	0	0.0%
A23 Peak-Ctrl Tier Sm C&I Tr Transformed																
Cust Chg	Bills	0	0	0	$57.34	$57.34	$61.72	$61.72	0	0	0	0	0	0	0	0.0%
Energy	MWH	0	0	0	$31.40	$31.40	$41.25	$41.25	0	0	0	0	0	0	0	0.0%
Energy Cr	MWH	0	0	0	-$15.18	-$15.18	-$18.68	-$18.68	0	0	0	0	0	0	0	0.0%
Demand	KW	0	0	0	$13.24	$8.94	$15.54	$10.93	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$7.33	$7.33	$9.36	$9.36	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$6.31	$6.31	$8.21	$8.21	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$5.79	$5.79	$7.67	$7.67	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$5.60	$5.60	$7.47	$7.47	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$5.01	$5.01	$6.85	$6.85	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$4.54	$4.54	$6.35	$6.35	0	0	0	0	0	0	0	0.0%
Fuel Cost	MWH	0	0	0	$28.09	$28.09	$28.16	$28.16	0	0	0	0	0	0	0	0.0%
Riders	KW	0	0	0	$0.99	$0.99	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Riders	MWH	0	0	0	$2.47	$2.47	$1.31	$1.31	0	0	0	0	0	0	0	0.0%
Total:									0	0	0	0	0	0	0	0.0%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
		Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A23 Peak-Ctrl Tier Sm C&I Transmission																
Cust Chg	Bills	8	16	24	$57.34	$57.34	$61.72	$61.72	0	1	1	0	1	1	0	7.6%
Energy	MWH	1,091	2,236	3,327	$31.30	$31.30	$41.14	$41.14	34	70	104	45	92	137	33	31.4%
Energy Cr	MWH	0	0	0	-$15.18	-$15.18	-$18.68	-$18.68	0	0	0	0	0	0	0	0.0%
Demand	KW	198	412	610	$12.44	$8.14	$14.54	$9.93	2	3	6	3	4	7	1	19.8%
Control Dmd	KW	960	1,523	2,483	$6.53	$6.53	$8.36	$8.36	6	10	16	8	13	21	5	28.0%
Control Dmd	KW	0	0	0	$5.51	$5.51	$7.21	$7.21	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	2,851	6,131	8,982	$4.99	$4.99	$6.67	$6.67	14	31	45	19	41	60	15	33.7%
Control Dmd	KW	0	0	0	$4.80	$4.80	$6.47	$6.47	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$4.21	$4.21	$5.85	$5.85	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$3.74	$3.74	$5.35	$5.35	0	0	0	0	0	0	0	0.0%
Fuel Cost	MWH	1,091	2,236	3,327	$28.09	$28.09	$28.16	$28.16	31	63	93	31	63	94	0	0.3%
Riders	KW	4,009	8,066	12,075	$0.99	$0.99	$0.00	$0.00	4	8	12	0	0	0	-12	-100.0%
Riders	MWH	1,091	2,236	3,327	$2.47	$2.47	$1.31	$1.31	3	6	8	1	3	4	-4	-46.8%
Total:									95	191	286	107	217	324	38	13.3%
A23 Peak-Ctrl Tier Lg C&I Transmission																
Cust Chg	Bills	4	8	12	$57.34	$57.34	$61.72	$61.72	0	0	1	0	0	1	0	7.6%
Energy	MWH	1,296	2,626	3,922	$31.30	$31.30	$41.14	$41.14	41	82	123	53	108	161	39	31.4%
Energy Cr	MWH	0	0	0	-$15.18	-$15.18	-$18.68	-$18.68	0	0	0	0	0	0	0	0.0%
Demand	KW	120	254	374	$12.44	$8.14	$14.54	$9.93	1	2	4	2	3	4	1	19.8%
Control Dmd	KW	0	0	0	$6.53	$6.53	$8.36	$8.36	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$5.51	$5.51	$7.21	$7.21	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	3,980	7,760	11,740	$4.99	$4.99	$6.67	$6.67	20	39	59	27	52	78	20	33.7%
Control Dmd	KW	0	0	0	$4.80	$4.80	$6.47	$6.47	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$4.21	$4.21	$5.85	$5.85	0	0	0	0	0	0	0	0.0%
Control Dmd	KW	0	0	0	$3.74	$3.74	$5.35	$5.35	0	0	0	0	0	0	0	0.0%
Fuel Cost	MWH	1,296	2,626	3,922	$28.09	$28.09	$28.16	$28.16	36	74	110	37	74	110	0	0.3%
Riders	KW	4,101	8,014	12,114	$0.99	$0.99	$0.00	$0.00	4	8	12	0	0	0	-12	-100.0%
Riders	MWH	1,296	2,626	3,922	$2.47	$2.47	$1.31	$1.31	3	6	10	2	3	5	-5	-46.8%
Total:									106	212	317	120	240	360	43	13.5%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A24 Peak-Ctrl Tier TOD Sm C&I Secondary																	
Cust Chg		Bills	784	1,571	2,355	$57.34	$57.34	$61.72	$61.72	45	90	135	48	97	145	10	7.6%
Energy	On	MWH	57,014	102,709	159,723	$48.55	$48.55	$62.96	$62.96	2,768	4,987	7,755	3,590	6,467	10,056	2,302	29.7%
Energy	Off	MWH	88,570	162,287	250,857	$23.41	$23.41	$30.71	$30.71	2,073	3,799	5,873	2,720	4,984	7,704	1,831	31.2%
Energy Cr		MWH	24,527	46,117	70,644	-$15.18	-$15.18	-$18.68	-$18.68	-372	-700	-1,072	-458	-861	-1,320	-247	23.1%
Demand		KW	105,313	194,545	299,858	$14.79	$10.49	$17.54	$12.93	1,558	2,041	3,598	1,847	2,515	4,363	764	21.2%
Off Dmd		KW	7,910	25,428	33,338	$2.35	$2.35	$3.00	$3.00	19	60	78	24	76	100	22	27.7%
Control Dmd		KW	50,944	82,932	133,877	$8.88	$8.88	$11.36	$11.36	452	736	1,189	579	942	1,521	332	27.9%
Control Dmd		KW	39,867	71,056	110,923	$7.86	$7.86	$10.21	$10.21	313	558	872	407	725	1,133	261	29.9%
Control Dmd		KW	117,574	205,605	323,179	$7.34	$7.34	$9.67	$9.67	863	1,509	2,372	1,137	1,988	3,125	753	31.7%
Control Dmd		KW	3,776	7,220	10,997	$7.15	$7.15	$9.47	$9.47	27	52	79	36	68	104	26	32.4%
Control Dmd		KW	10,970	20,019	30,989	$6.56	$6.56	$8.85	$8.85	72	131	203	97	177	274	71	34.9%
Control Dmd		KW	0	0	0	$6.09	$6.09	$8.35	$8.35	0	0	0	0	0	0	0	0.0%
AnnMinDmd		KW	1,052	2,104	3,156	$1.00	$1.00	$1.32	$1.32	1	2	3	1	3	4	1	32.0%
Fuel Cost	On	MWH	57,014	102,709	159,723	$35.13	$35.13	$35.20	$35.20	2,003	3,608	5,611	2,007	3,615	5,622	11	0.2%
Fuel Cost	Off	MWH	88,570	162,287	250,857	$22.98	$22.98	$23.04	$23.04	2,035	3,729	5,764	2,040	3,739	5,779	15	0.3%
Riders		KW	328,445	581,377	909,821	$0.99	$0.99	$0.00	$0.00	326	578	904	0	0	0	-904	-100.0%
Riders		MWH	145,585	264,995	410,580	$2.47	$2.47	$1.31	$1.31	359	654	1,013	191	348	539	-474	-46.8%
Total:										12,543	21,834	34,376	14,266	24,883	39,149	4,773	13.9%
A24 Peak-Ctrl Tier TOD Lg C&I Secondary																	
Cust Chg		Bills	204	408	612	$57.34	$57.34	$61.72	$61.72	12	23	35	13	25	38	3	7.6%
Energy	On	MWH	56,782	102,106	158,888	$48.55	$48.55	$62.96	$62.96	2,757	4,957	7,714	3,575	6,429	10,004	2,290	29.7%
Energy	Off	MWH	85,001	152,401	237,403	$23.41	$23.41	$30.71	$30.71	1,990	3,568	5,558	2,610	4,680	7,291	1,733	31.2%
Energy Cr		MWH	22,875	39,840	62,715	-$15.18	-$15.18	-$18.68	-$18.68	-347	-605	-952	-427	-744	-1,172	-220	23.1%
Demand		KW	112,761	208,713	321,474	$14.79	$10.49	$17.54	$12.93	1,668	2,189	3,857	1,978	2,699	4,676	819	21.2%
Off Dmd		KW	4,226	7,589	11,816	$2.35	$2.35	$3.00	$3.00	10	18	28	13	23	35	8	27.7%
Control Dmd		KW	47,179	92,439	139,618	$8.88	$8.88	$11.36	$11.36	419	821	1,240	536	1,050	1,586	346	27.9%
Control Dmd		KW	22,971	44,632	67,603	$7.86	$7.86	$10.21	$10.21	181	351	531	235	456	690	159	29.9%
Control Dmd		KW	115,090	198,084	313,175	$7.34	$7.34	$9.67	$9.67	845	1,454	2,299	1,113	1,915	3,028	730	31.7%
Control Dmd		KW	5,339	9,827	15,167	$7.15	$7.15	$9.47	$9.47	38	70	108	51	93	144	35	32.4%
Control Dmd		KW	31,773	57,449	89,222	$6.56	$6.56	$8.85	$8.85	208	377	585	281	508	790	204	34.9%
Control Dmd		KW	0	0	0	$6.09	$6.09	$8.35	$8.35	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	56,782	102,106	158,888	$35.13	$35.13	$35.20	$35.20	1,995	3,587	5,582	1,999	3,594	5,593	11	0.2%
Fuel Cost	Off	MWH	85,001	152,401	237,403	$22.98	$22.98	$23.04	$23.04	1,953	3,502	5,455	1,958	3,511	5,469	14	0.3%
Riders		KW	335,113	611,145	946,259	$0.99	$0.99	$0.00	$0.00	333	607	940	0	0	0	-940	-100.0%
Riders		MWH	141,783	254,508	396,291	$2.47	$2.47	$1.31	$1.31	350	628	977	186	334	520	-458	-46.8%
Total:										12,410	21,547	33,958	14,119	24,573	38,692	4,734	13.9%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A24 Peak-Ctrl Tier TOD Sm C&I Primary																	
Cust Chg		Bills	68	136	204	$57.34	$57.34	$61.72	$61.72	4	8	12	4	8	13	1	7.6%
Energy	On	MWH	8,846	15,220	24,066	$47.50	$47.50	$61.72	$61.72	420	723	1,143	546	939	1,485	342	29.9%
Energy	Off	MWH	14,920	25,108	40,027	$22.36	$22.36	$29.47	$29.47	334	561	895	440	740	1,180	285	31.8%
Energy Cr		MWH	4,644	8,474	13,118	-$15.18	-$15.18	-$18.68	-$18.68	-70	-129	-199	-87	-158	-245	-46	23.1%
Demand		KW	18,499	30,829	49,327	$13.99	$9.69	$16.94	$12.33	259	299	558	313	380	693	136	24.4%
Off Dmd		KW	2,800	5,461	8,261	$1.55	$1.55	$2.40	$2.40	4	8	13	7	13	20	7	54.8%
Control Dmd		KW	6,995	15,207	22,202	$8.08	$8.08	$10.76	$10.76	57	123	179	75	164	239	60	33.2%
Control Dmd		KW	4,484	5,202	9,687	$7.06	$7.06	$9.61	$9.61	32	37	68	43	50	93	25	36.1%
Control Dmd		KW	16,222	26,446	42,668	$6.54	$6.54	$9.07	$9.07	106	173	279	147	240	387	108	38.7%
Control Dmd		KW	0	0	0	$6.35	$6.35	$8.87	$8.87	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	5,027	8,064	13,091	$5.76	$5.76	$8.25	$8.25	29	46	75	41	67	108	33	43.2%
Control Dmd		KW	0	0	0	$5.29	$5.29	$7.75	$7.75	0	0	0	0	0	0	0	0.0%
AnnMinDmdChg		KW	0	0	0	$1.00	$1.00	$1.32	$1.32	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	8,846	15,220	24,066	$35.13	$35.13	$35.20	$35.20	311	535	845	311	536	847	2	0.2%
Fuel Cost	Off	MWH	14,920	25,108	40,027	$22.98	$22.98	$23.04	$23.04	343	577	920	344	578	922	2	0.3%
Riders		KW	51,227	85,748	136,975	$0.99	$0.99	$0.00	$0.00	51	85	136	0	0	0	-136	-100.0%
Riders		MWH	23,766	40,328	64,094	$2.47	$2.47	$1.31	$1.31	59	99	158	31	53	84	-74	-46.8%
Total:										1,937	3,146	5,083	2,216	3,610	5,826	743	14.6%
A24 Peak-Ctrl Tier TOD Lg C&I Primary																	
Cust Chg		Bills	296	592	888	$57.34	$57.34	$61.72	$61.72	17	34	51	18	37	55	4	7.6%
Energy	On	MWH	168,302	295,459	463,761	$47.50	$47.50	$61.72	$61.72	7,995	14,035	22,029	10,388	18,236	28,623	6,594	29.9%
Energy	Off	MWH	260,764	461,684	722,449	$22.36	$22.36	$29.47	$29.47	5,831	10,324	16,155	7,685	13,606	21,291	5,136	31.8%
Energy Cr		MWH	73,887	147,747	221,634	-$15.18	-$15.18	-$18.68	-$18.68	-1,122	-2,243	-3,364	-1,380	-2,760	-4,140	-776	23.1%
Demand		KW	398,684	701,179	1,099,863	$13.99	$9.69	$16.94	$12.33	5,578	6,794	12,372	6,754	8,646	15,399	3,027	24.5%
Off Dmd		KW	12,245	25,727	37,972	$1.55	$1.55	$2.40	$2.40	19	40	59	29	62	91	32	54.8%
Control Dmd		KW	36,152	59,956	96,108	$8.08	$8.08	$10.76	$10.76	292	484	777	389	645	1,034	258	33.2%
Control Dmd		KW	80,690	135,967	216,658	$7.06	$7.06	$9.61	$9.61	570	960	1,530	775	1,307	2,082	552	36.1%
Control Dmd		KW	263,985	440,534	704,519	$6.54	$6.54	$9.07	$9.07	1,726	2,881	4,608	2,394	3,996	6,390	1,782	38.7%
Control Dmd		KW	38,460	58,567	97,027	$6.35	$6.35	$8.87	$8.87	244	372	616	341	519	861	245	39.7%
Control Dmd		KW	86,366	149,332	235,697	$5.76	$5.76	$8.25	$8.25	497	860	1,358	713	1,232	1,945	587	43.2%
Control Dmd		KW	48,883	100,339	149,222	$5.29	$5.29	$7.75	$7.75	259	531	789	379	778	1,156	367	46.5%
BIS Rdr		KW	5,316	12,717	18,033	-$3.08	-$2.13	-$3.73	-$2.71	-16	-27	-43	-20	-34	-54	-11	24.9%
Fuel Cost	On	MWH	168,302	295,459	463,761	$35.13	$35.13	$35.20	$35.20	5,913	10,380	16,293	5,924	10,400	16,324	31	0.2%
Fuel Cost	Off	MWH	260,764	461,684	722,449	$22.98	$22.98	$23.04	$23.04	5,992	10,608	16,600	6,007	10,636	16,643	43	0.3%
Riders		KW	953,220	1,645,875	2,599,095	$0.99	$0.99	$0.00	$0.00	947	1,635	2,582	0	0	0	-2,582	-100.0%
Riders		MWH	429,066	757,144	1,186,210	$2.47	$2.47	$1.31	$1.31	1,058	1,868	2,926	563	993	1,556	-1,370	-46.8%
Total:										35,799	59,536	95,335	40,959	68,296	109,255	13,920	14.6%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A24 Peak-Ctrl Tier TOD Lg C&I Tr Transformed																	
Cust Chg		Bills	20	40	60	$57.34	$57.34	$61.72	$61.72	1	2	3	1	2	4	0	7.6%
Energy	On	MWH	46,265	87,075	133,340	$45.88	$45.88	$59.91	$59.91	2,123	3,995	6,118	2,772	5,217	7,989	1,871	30.6%
Energy	Off	MWH	74,792	142,525	217,317	$20.74	$20.74	$27.66	$27.66	1,551	2,956	4,507	2,069	3,942	6,011	1,504	33.4%
Energy Cr		MWH	26,299	51,764	78,062	-$15.18	-$15.18	-$18.68	-$18.68	-399	-786	-1,185	-491	-967	-1,458	-273	23.1%
Demand		KW	84,235	158,875	243,110	$13.24	$8.94	$15.54	$10.93	1,115	1,420	2,536	1,309	1,737	3,046	510	20.1%
Off Dmd		KW	2,391	4,988	7,379	$0.80	$0.80	$1.00	$1.00	2	4	6	2	5	7	1	25.0%
Control Dmd		KW	14,213	24,825	39,038	$7.33	$7.33	$9.36	$9.36	104	182	286	133	232	365	79	27.7%
Control Dmd		KW	0	0	0	$6.31	$6.31	$8.21	$8.21	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	49,813	91,962	141,776	$5.79	$5.79	$7.67	$7.67	288	532	821	382	705	1,087	267	32.5%
Control Dmd		KW	0	0	0	$5.60	$5.60	$7.47	$7.47	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$5.01	$5.01	$6.85	$6.85	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	96,346	179,607	275,953	$4.54	$4.54	$6.35	$6.35	437	815	1,253	612	1,141	1,752	499	39.9%
Fuel Cost	On	MWH	46,265	87,075	133,340	$35.13	$35.13	$35.20	$35.20	1,625	3,059	4,685	1,628	3,065	4,693	9	0.2%
Fuel Cost	Off	MWH	74,792	142,525	217,317	$22.98	$22.98	$23.04	$23.04	1,718	3,275	4,993	1,723	3,283	5,006	13	0.3%
Riders		KW	244,607	455,270	699,877	$0.99	$0.99	$0.00	$0.00	243	452	695	0	0	0	-695	-100.0%
Riders		MWH	121,056	229,601	350,657	$2.47	$2.47	$1.31	$1.31	299	566	865	159	301	460	-405	-46.8%
Total:										9,108	16,474	25,583	10,299	18,664	28,963	3,380	13.2%
A24 Peak-Ctrl Tier TOD Sm C&I Transmission																	
Cust Chg		Bills	0	0	0	$57.34	$57.34	$61.72	$61.72	0	0	0	0	0	0	0	0.0%
Energy	On	MWH	0	0	0	$45.78	$45.78	$59.80	$59.80	0	0	0	0	0	0	0	0.0%
Energy	Off	MWH	0	0	0	$20.64	$20.64	$27.55	$27.55	0	0	0	0	0	0	0	0.0%
Energy Cr		MWH	0	0	0	-$15.18	-$15.18	-$18.68	-$18.68	0	0	0	0	0	0	0	0.0%
Demand		KW	0	0	0	$12.44	$8.14	$14.54	$9.93	0	0	0	0	0	0	0	0.0%
Off Dmd		KW	0	0	0	$0.00	$0.00	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$6.53	$6.53	$8.36	$8.36	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$5.51	$5.51	$7.21	$7.21	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$4.99	$4.99	$6.67	$6.67	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$4.80	$4.80	$6.47	$6.47	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$4.21	$4.21	$5.85	$5.85	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$3.74	$3.74	$5.35	$5.35	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	0	0	0	$35.13	$35.13	$35.20	$35.20	0	0	0	0	0	0	0	0.0%
Fuel Cost	Off	MWH	0	0	0	$22.98	$22.98	$23.04	$23.04	0	0	0	0	0	0	0	0.0%
Riders		KW	0	0	0	$0.99	$0.99	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Riders		MWH	0	0	0	$2.47	$2.47	$1.31	$1.31	0	0	0	0	0	0	0	0.0%
Total:										0	0	0	0	0	0	0	0.0%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A24 Peak-Ctrl Tier TOD Lg C&I Transmission																	
Cust Chg		Bills	4	8	12	$57.34	$57.34	$61.72	$61.72	0	0	1	0	0	1	0	7.6%
Energy	On	MWH	449	1,074	1,523	$45.78	$45.78	$59.80	$59.80	21	49	70	27	64	91	21	30.6%
Energy	Off	MWH	1,199	2,462	3,661	$20.64	$20.64	$27.55	$27.55	25	51	76	33	68	101	25	33.5%
Energy Cr		MWH	0	38	38	-$15.18	-$15.18	-$18.68	-$18.68	0	-1	-1	0	-1	-1	0	23.1%
Demand		KW	0	0	0	$12.44	$8.14	$14.54	$9.93	0	0	0	0	0	0	0	0.0%
Off Dmd		KW	0	0	0	$0.00	$0.00	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$6.53	$6.53	$8.36	$8.36	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$5.51	$5.51	$7.21	$7.21	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$4.99	$4.99	$6.67	$6.67	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$4.80	$4.80	$6.47	$6.47	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	17,860	30,071	47,931	$4.21	$4.21	$5.85	$5.85	75	127	202	104	176	280	79	39.0%
Control Dmd		KW	0	0	0	$3.74	$3.74	$5.35	$5.35	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	449	1,074	1,523	$35.13	$35.13	$35.20	$35.20	16	38	54	16	38	54	0	0.2%
Fuel Cost	Off	MWH	1,199	2,462	3,661	$22.98	$22.98	$23.04	$23.04	28	57	84	28	57	84	0	0.3%
Riders		KW	17,860	30,071	47,931	$0.99	$0.99	$0.00	$0.00	18	30	48	0	0	0	-48	-100.0%
Riders		MWH	1,649	3,535	5,184	$2.47	$2.47	$1.31	$1.31	4	9	13	2	5	7	-6	-46.8%
Total:										186	359	545	210	407	617	72	13.2%
A27 Energy-Control Rider Sm C&I Secondary																	
Cust Chg		Bills	16	32	48	$57.34	$57.34	$61.72	$61.72	1	2	3	1	2	3	0	7.6%
Energy	On	MWH	55	114	168	$48.55	$48.55	$62.96	$62.96	3	6	8	3	7	11	2	29.7%
Energy	OnC	MWH	1,573	2,789	4,362	$46.47	$46.47	$60.86	$60.86	73	130	203	96	170	265	63	31.0%
Energy	Off	MWH	98	208	306	$23.41	$23.41	$30.71	$30.71	2	5	7	3	6	9	2	31.2%
Energy	OffC	MWH	2,326	4,203	6,529	$22.80	$22.80	$30.47	$30.47	53	96	149	71	128	199	50	33.6%
Energy Cr		MWH	524	1,099	1,623	-$15.18	-$15.18	-$18.68	-$18.68	-8	-17	-25	-10	-21	-30	-6	23.1%
Demand		KW	221	458	679	$14.79	$10.49	$17.54	$12.93	3	5	8	4	6	10	2	21.4%
Off Dmd		KW	12	64	76	$2.35	$2.35	$3.00	$3.00	0	0	0	0	0	0	0	27.7%
Control Dmd		KW	0	0	0	$7.15	$7.15	$9.47	$9.47	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	6,882	10,759	17,641	$6.56	$6.56	$8.85	$8.85	45	71	116	61	95	156	40	34.9%
Control Dmd		KW	3,403	7,462	10,865	$6.09	$6.09	$8.35	$8.35	21	45	66	28	62	91	25	37.1%
Fuel Cost	On	MWH	1,627	2,903	4,530	$35.13	$35.13	$35.20	$35.20	57	102	159	57	102	159	0	0.2%
Fuel Cost	Off	MWH	2,423	4,411	6,835	$22.98	$22.98	$23.04	$23.04	56	101	157	56	102	157	0	0.3%
Riders		KW	10,506	18,678	29,185	$0.99	$0.99	$0.00	$0.00	10	19	29	0	0	0	-29	-100.0%
Riders		MWH	4,050	7,314	11,365	$2.47	$2.47	$1.31	$1.31	10	18	28	5	10	15	-13	-46.8%
Total:										326	582	908	376	670	1,046	137	15.1%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A27 Energy-Control Rider Lg C&I Secondary																	
Cust Chg		Bills	4	8	12	$57.34	$57.34	$61.72	$61.72	0	0	1	0	0	1	0	7.6%
Energy	On	MWH	0	0	0	$48.55	$48.55	$62.96	$62.96	0	0	0	0	0	0	0	0.0%
Energy	OnC	MWH	934	1,545	2,479	$46.47	$46.47	$60.86	$60.86	43	72	115	57	94	151	36	31.0%
Energy	Off	MWH	0	0	0	$23.41	$23.41	$30.71	$30.71	0	0	0	0	0	0	0	0.0%
Energy	OffC	MWH	1,569	2,571	4,140	$22.80	$22.80	$30.47	$30.47	36	59	94	48	78	126	32	33.6%
Energy Cr		MWH	659	1,031	1,690	-$15.18	-$15.18	-$18.68	-$18.68	-10	-16	-26	-12	-19	-32	-6	23.1%
Demand		KW	0	0	0	$14.79	$10.49	$17.54	$12.93	0	0	0	0	0	0	0	0.0%
Off Dmd		KW	4	26	30	$2.35	$2.35	$3.00	$3.00	0	0	0	0	0	0	0	27.7%
Control Dmd		KW	0	0	0	$7.15	$7.15	$9.47	$9.47	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	4,521	7,629	12,150	$6.56	$6.56	$8.85	$8.85	30	50	80	40	68	108	28	34.9%
Control Dmd		KW	0	0	0	$6.09	$6.09	$8.35	$8.35	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	934	1,545	2,479	$35.13	$35.13	$35.20	$35.20	33	54	87	33	54	87	0	0.2%
Fuel Cost	Off	MWH	1,569	2,571	4,140	$22.98	$22.98	$23.04	$23.04	36	59	95	36	59	95	0	0.3%
Riders		KW	4,521	7,629	12,150	$0.99	$0.99	$0.00	$0.00	4	8	12	0	0	0	-12	-100.0%
Riders		MWH	2,503	4,116	6,619	$2.47	$2.47	$1.31	$1.31	6	10	16	3	5	9	-8	-46.8%
Total:										179	296	475	205	340	545	70	14.8%
A27 Energy-Control Rider Sm C&I Primary																	
Cust Chg		Bills	4	8	12	$57.34	$57.34	$61.72	$61.72	0	0	1	0	0	1	0	7.6%
Energy	On	MWH	0	0	0	$47.50	$47.50	$61.72	$61.72	0	0	0	0	0	0	0	0.0%
Energy	OnC	MWH	1,633	3,174	4,807	$45.42	$45.42	$59.62	$59.62	74	144	218	97	189	287	68	31.3%
Energy	Off	MWH	0	0	0	$22.36	$22.36	$29.47	$29.47	0	0	0	0	0	0	0	0.0%
Energy	OffC	MWH	2,831	5,574	8,405	$21.75	$21.75	$29.23	$29.23	62	121	183	83	163	246	63	34.4%
Energy Cr		MWH	0	453	453	-$15.18	-$15.18	-$18.68	-$18.68	0	-7	-7	0	-8	-8	-2	23.1%
Demand		KW	0	0	0	$13.99	$9.69	$16.94	$12.33	0	0	0	0	0	0	0	0.0%
Off Dmd		KW	647	16	663	$1.55	$1.55	$2.40	$2.40	1	0	1	2	0	2	1	54.8%
Control Dmd		KW	0	0	0	$6.35	$6.35	$8.87	$8.87	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	6,882	10,759	17,641	$5.76	$5.76	$8.25	$8.25	40	62	102	57	89	146	44	43.2%
Control Dmd		KW	3,403	7,462	10,865	$5.29	$5.29	$7.75	$7.75	18	39	57	26	58	84	27	46.5%
Fuel Cost	On	MWH	1,633	3,174	4,807	$35.13	$35.13	$35.20	$35.20	57	112	169	57	112	169	0	0.2%
Fuel Cost	Off	MWH	2,831	5,574	8,405	$22.98	$22.98	$23.04	$23.04	65	128	193	65	128	194	1	0.3%
Riders		KW	10,285	18,221	28,506	$0.99	$0.99	$0.00	$0.00	10	18	28	0	0	0	-28	-100.0%
Riders		MWH	4,463	8,749	13,212	$2.47	$2.47	$1.31	$1.31	11	22	33	6	11	17	-15	-46.8%
Total:										338	640	978	394	742	1,136	158	16.2%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units Summer	Billing Units Winter	Billing Units Annual	Present Rate Summer	Present Rate Winter	Proposed Rate Summer	Proposed Rate Winter	Present Revenues Summer	Present Revenues Winter	Present Revenues Annual	Proposed Revenues Summer	Proposed Revenues Winter	Proposed Revenues Annual	Increase Annual	Pct Inc. Annual
A27 Energy-Control Rider Lg C&I Primary																	
Cust Chg		Bills	12	24	36	$57.34	$57.34	$61.72	$61.72	1	1	2	1	1	2	0	7.6%
Energy	On	MWH	0	0	0	$47.50	$47.50	$61.72	$61.72	0	0	0	0	0	0	0	0.0%
Energy	OnC	MWH	4,201	8,107	12,308	$45.42	$45.42	$59.62	$59.62	191	368	559	250	483	734	175	31.3%
Energy	Off	MWH	0	0	0	$22.36	$22.36	$29.47	$29.47	0	0	0	0	0	0	0	0.0%
Energy	OffC	MWH	6,825	13,502	20,327	$21.75	$21.75	$29.23	$29.23	148	294	442	199	395	594	152	34.4%
Energy Cr		MWH	2,886	6,110	8,997	-$15.18	-$15.18	-$18.68	-$18.68	-44	-93	-137	-54	-114	-168	-31	23.1%
Demand		KW	0	0	0	$13.99	$9.69	$16.94	$12.33	0	0	0	0	0	0	0	0.0%
Off Dmd		KW	17	57	74	$1.55	$1.55	$2.40	$2.40	0	0	0	0	0	0	0	54.8%
Control Dmd		KW	0	663	663	$6.35	$6.35	$8.87	$8.87	0	4	4	0	6	6	2	39.7%
Control Dmd		KW	20,407	37,727	58,134	$5.76	$5.76	$8.25	$8.25	118	217	335	168	311	480	145	43.2%
Control Dmd		KW	0	0	0	$5.29	$5.29	$7.75	$7.75	0	0	0	0	0	0	0	0.0%
Fuel Cost	On	MWH	4,201	8,107	12,308	$35.13	$35.13	$35.20	$35.20	148	285	432	148	285	433	1	0.2%
Fuel Cost	Off	MWH	6,825	13,502	20,327	$22.98	$22.98	$23.04	$23.04	157	310	467	157	311	468	1	0.3%
Riders		KW	20,407	38,390	58,797	$0.99	$0.99	$0.00	$0.00	20	38	58	0	0	0	-58	-100.0%
Riders		MWH	11,026	21,609	32,635	$2.47	$2.47	$1.31	$1.31	27	53	80	14	28	43	-38	-46.8%
Total:										766	1,479	2,244	885	1,707	2,592	348	15.5%
A27 Energy-Control Rider Lg C&I Tr Transformed																	
Cust Chg		Bills	8	16	24	$57.34	$57.34	$61.72	$61.72	0	1	1	0	1	1	0	7.6%
Energy	On	MWH	1,109	2,100	3,209	$45.88	$45.88	$59.91	$59.91	51	96	147	66	126	192	45	30.6%
Energy	OnC	MWH	41,114	75,931	117,045	$43.80	$43.80	$57.81	$57.81	1,801	3,326	5,127	2,377	4,390	6,766	1,640	32.0%
Energy	Off	MWH	2,095	3,850	5,945	$20.74	$20.74	$27.66	$27.66	43	80	123	58	106	164	41	33.4%
Energy	OffC	MWH	76,344	138,836	215,180	$20.13	$20.13	$27.42	$27.42	1,537	2,795	4,332	2,093	3,807	5,900	1,569	36.2%
Energy Cr		MWH	33,106	57,149	90,255	-$15.18	-$15.18	-$18.68	-$18.68	-503	-868	-1,370	-618	-1,068	-1,686	-316	23.1%
Demand		KW	4,409	8,291	12,699	$13.24	$8.94	$15.54	$10.93	58	74	132	69	91	159	27	20.1%
Off Dmd		KW	47,909	96,449	144,358	$0.80	$0.80	$1.00	$1.00	38	77	115	48	96	144	29	25.0%
Control Dmd		KW	0	0	0	$5.60	$5.60	$7.47	$7.47	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	0	0	0	$5.01	$5.01	$6.85	$6.85	0	0	0	0	0	0	0	0.0%
Control Dmd		KW	379,805	717,665	1,097,470	$4.54	$4.54	$6.35	$6.35	1,724	3,258	4,983	2,412	4,557	6,969	1,986	39.9%
Fuel Cost	On	MWH	42,222	78,031	120,254	$35.13	$35.13	$35.20	$35.20	1,483	2,741	4,225	1,486	2,747	4,233	8	0.2%
Fuel Cost	Off	MWH	78,439	142,686	221,125	$22.98	$22.98	$23.04	$23.04	1,802	3,278	5,081	1,807	3,287	5,094	13	0.3%
Riders		KW	384,213	725,956	1,110,169	$0.99	$0.99	$0.00	$0.00	382	721	1,103	0	0	0	-1,103	-100.0%
Riders		MWH	120,662	220,717	341,379	$2.47	$2.47	$1.31	$1.31	298	544	842	158	290	448	-394	-46.8%
Total:										8,716	16,125	24,841	9,956	18,430	28,386	3,545	14.3%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
Standby and Supplemental																	
Cust Chg	A14	Bills	4	8	12	$25.64	$25.64	$27.00	$27.00	0	0	0	0	0	0	0	5.3%
Cust Chg	A15	Bills	8	16	24	$25.64	$25.64	$27.00	$27.00	0	0	1	0	0	1	0	5.3%
Cust Chg	A15	Bills	8	16	24	$25.64	$25.64	$27.00	$27.00	0	0	1	0	0	1	0	5.3%
Cust Chg	A15	Bills	12	24	36	$25.64	$25.64	$27.00	$27.00	0	1	1	0	1	1	0	5.3%
Cust Chg	A15	Bills	8	16	24	$25.64	$25.64	$27.00	$27.00	0	0	1	0	0	1	0	5.3%
Cust Chg	A24	Bills	8	16	24	$25.64	$25.64	$27.00	$27.00	0	0	1	0	0	1	0	5.3%
Cust Chg	A24	Bills	4	8	12	$25.64	$25.64	$27.00	$27.00	0	0	0	0	0	0	0	5.3%
DemandU	A14	KW	2,000	4,000	6,000	$3.06	$3.06	$3.85	$3.85	6	12	18	8	15	23	5	25.8%
DemandU	A15	KW	2,532	5,064	7,596	$2.26	$2.26	$3.25	$3.25	6	11	17	8	16	25	8	43.8%
DemandU	A15	KW	12,000	24,000	36,000	$3.06	$3.06	$3.85	$3.85	37	73	110	46	92	139	28	25.8%
DemandU	A15	KW	8,000	16,000	24,000	$3.06	$3.06	$3.85	$3.85	24	49	73	31	62	92	19	25.8%
DemandU	A24	KW	13,000	26,000	39,000	$2.26	$2.26	$3.25	$3.25	29	59	88	42	85	127	39	43.8%
DemandS	A15	KW	20,000	40,000	60,000	$1.51	$1.51	$1.85	$1.85	30	60	91	37	74	111	20	22.5%
DemandS	A15	KW	269,858	457,527	727,385	$0.71	$0.71	$0.85	$0.85	192	325	516	229	389	618	102	19.7%
DemandS	A24	KW	16,000	32,000	48,000	$1.41	$1.41	$1.75	$1.75	23	45	68	28	56	84	16	24.1%
DmdSup	A15	KW	0	8,563	8,563	$1.85	$1.85	$2.28	$2.28	0	16	16	0	20	20	4	23.2%
DmdSup	A15	KW	28,000	56,000	84,000	$1.05	$1.05	$1.28	$1.28	29	59	88	36	72	108	19	21.9%
DmdSup	A24	KW	2,000	4,000	6,000	$2.60	$2.60	$3.68	$3.68	5	10	16	7	15	22	6	41.5%
DmdSup	A24	KW	14,000	24,500	38,500	$1.85	$1.85	$2.28	$2.28	26	45	71	32	56	88	17	23.2%
PkSurchg	A14	MWH	0	1	1	$63.12	$41.30	$73.78	$50.38	0	0	0	0	0	0	0	21.9%
PkSurchg	A15	MWH	13	43	55	$63.12	$41.30	$73.78	$50.38	1	2	3	1	2	3	1	20.4%
PkSurchg	A15	MWH	181	501	682	$63.12	$41.30	$73.78	$50.38	11	21	32	13	25	39	6	20.2%
PkSurchg	A15	MWH	4,015	7,817	11,832	$63.12	$41.30	$73.78	$50.38	253	323	576	296	394	690	114	19.7%
PkSurchg	A15	MWH	0	346	346	$63.12	$41.30	$73.78	$50.38	0	14	14	0	17	17	3	22.0%
PkSurchg	A15	MWH	1,454	975	2,429	$63.12	$41.30	$73.78	$50.38	92	40	132	107	49	156	24	18.4%
PkSurchg	A15	MWH	0	0	0	$63.12	$41.30	$73.78	$50.38	0	0	0	0	0	0	0	0.0%
Riders	A14	KW	2,000	4,000	6,000	$0.99	$0.99	$0.00	$0.00	2	4	6	0	0	0	-6	-100.0%
Riders	A15	KW	2,532	5,064	7,596	$0.99	$0.99	$0.00	$0.00	3	5	8	0	0	0	-8	-100.0%
Riders	A15	KW	12,000	24,000	36,000	$0.99	$0.99	$0.00	$0.00	12	24	36	0	0	0	-36	-100.0%
Riders	A15	KW	8,000	16,000	24,000	$0.99	$0.99	$0.00	$0.00	8	16	24	0	0	0	-24	-100.0%
Riders	A24	KW	13,000	26,000	39,000	$0.99	$0.99	$0.00	$0.00	13	26	39	0	0	0	-39	-100.0%
Riders	A15	KW	20,000	40,000	60,000	$0.99	$0.99	$0.00	$0.00	20	40	60	0	0	0	-60	-100.0%
Riders	A15	KW	269,858	457,527	727,385	$0.99	$0.99	$0.00	$0.00	268	455	723	0	0	0	-723	-100.0%
Riders	A24	KW	16,000	32,000	48,000	$0.99	$0.99	$0.00	$0.00	16	32	48	0	0	0	-48	-100.0%
Riders	A15	KW	0	8,563	8,563	$0.99	$0.99	$0.00	$0.00	0	9	9	0	0	0	-9	-100.0%
Riders	A15	KW	28,000	56,000	84,000	$0.99	$0.99	$0.00	$0.00	28	56	83	0	0	0	-83	-100.0%
Riders	A24	KW	2,000	4,000	6,000	$0.99	$0.99	$0.00	$0.00	2	4	6	0	0	0	-6	-100.0%
Riders	A24	KW	14,000	24,500	38,500	$0.99	$0.99	$0.00	$0.00	14	24	38	0	0	0	-38	-100.0%
Total:										1,151	1,861	3,012	924	1,442	2,366	-647	-21.5%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge		Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
PV Demand Credit Rider																	
Cust Chg	A14	Bills	200	400	600	$25.75	$25.75	$27.00	$27.00	5	10	15	5	11	16	1	4.9%
Cust Chg	A14	Bills	40	80	120	$25.75	$25.75	$27.00	$27.00	1	2	3	1	2	3	0	4.9%
Cust Chg	A15	Bills	120	240	360	$25.75	$25.75	$27.00	$27.00	3	6	9	3	6	10	0	4.9%
Cust Chg	A15	Bills	40	80	120	$25.75	$25.75	$27.00	$27.00	1	2	3	1	2	3	0	4.9%
Dmd Credit	A14	MWH	3,432	3,109	6,542	-$71.39	-$71.39	-$71.39	-$71.39	-245	-222	-467	-245	-222	-467	0	0.0%
Dmd Credit	A14	MWH	686	622	1,308	-$71.39	-$71.39	-$71.39	-$71.39	-49	-44	-93	-49	-44	-93	0	0.0%
Dmd Credit	A15	MWH	2,059	1,866	3,925	-$71.39	-$71.39	-$71.39	-$71.39	-147	-133	-280	-147	-133	-280	0	0.0%
Dmd Credit	A15	MWH	686	622	1,308	-$71.39	-$71.39	-$71.39	-$71.39	-49	-44	-93	-49	-44	-93	0	0.0%
Total:										-480	-423	-903	-479	-422	-902	2	-0.2%
A62 Real Time Pricing Lg C&I Primary																	
Cust Chg		Bills	12	24	36	$302.34	$302.34	$32.72	$32.72	4	7	11	0	1	1	-10	-89.2%
Energy		MWH	0	0	0	$0.00	$0.00	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Energy Cr		MWH	1,100	2,705	3,804	-$11.43	-$11.43	$0.00	$0.00	-13	-31	-43	0	0	0	43	-100.0%
Energy Cr		MWH	632	1,804	2,436	$0.00	$0.00	-$18.68	-$18.68	0	0	0	-12	-34	-46	-46	0.0%
LtdSurChg		MWH	50	101	151	$200.00	$200.00	$0.00	$0.00	10	20	30	0	0	0	-30	-100.0%
Demand		KW	16,773	27,944	44,718	$9.94	$9.94	$16.94	$12.33	167	278	444	316	404	720	276	62.0%
Dist Dmd		KW	29,018	48,345	77,363	$0.97	$0.97	$2.40	$2.40	28	47	75	4	6	9	-66	-87.7%
Energy		KW	2,617	4,748	7,365	$37.70	$27.15	$61.72	$61.72	99	129	228	161	293	455	227	99.8%
Energy		KW	4,764	8,708	13,472	$37.70	$27.15	$29.47	$29.47	180	236	416	140	257	397	-19	-4.6%
Fuel Cost	On	MWH	2,617	4,748	7,365	$35.13	$35.13	$35.20	$35.20	92	167	259	92	167	259	0	0.2%
Fuel Cost	Off	MWH	4,764	8,708	13,472	$22.98	$22.98	$23.04	$23.04	109	200	310	110	201	310	1	0.3%
Riders		KW	16,773	27,944	44,718	$0.99	$0.99	$0.00	$0.00	17	28	44	0	0	0	-44	-100.0%
Riders		MWH	7,381	13,456	20,837	$2.47	$2.47	$1.31	$1.31	18	33	51	10	18	27	-24	-46.8%
Total:										710	1,114	1,825	822	1,312	2,134	309	16.9%
A42 Siren Service Public Auth Secondary																	
HP		HP	15,204	30,408	45,612	$0.76	$0.76	$0.83	$0.83	12	23	35	13	25	38	3	9.2%
Total:										12	23	35	13	25	38	3	9.2%
Interdepartmental																	
Cust Chg			20	40	60	$0.00	$0.00	$0.00	$0.00	0	0	0	0	0	0	0	0.0%
Energy			3,295	3,813	7,108	$72.19	$67.25	$72.19	$67.25	238	256	494	238	256	494	0	0.0%
Fuel Cost			3,295	3,813	7,108	$28.09	$28.09	$28.16	$28.16	93	107	200	93	107	200	1	0.3%
Riders		MWH	3,295	3,813	7,108	$5.88	$5.88	$1.31	$1.31	19	22	42	4	5	9	-33	-77.7%
Total:										350	386	736	335	369	704	-32	-4.3%

[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS]

[HIGHLY CONFIDENTIAL TRADE SECRET ENDS]

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
		Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A07 Protective Ltg ResReg Secondary																
A100S	Lts	28,352	56,704	85,056	$7.34	$7.34	$8.99	$8.99	208	416	624	255	510	765	140	22.5%
A175M	Lts	10,960	21,920	32,880	$7.34	$7.34	$8.99	$8.99	80	161	241	99	197	296	54	22.5%
A250S	Lts	936	1,872	2,808	$11.64	$11.64	$14.45	$14.45	11	22	33	14	27	41	8	24.1%
A400M	Lts	252	504	756	$11.64	$11.64	$14.45	$14.45	3	6	9	4	7	11	2	24.1%
D250S	Lts	408	816	1,224	$12.62	$12.62	$15.10	$15.10	5	10	15	6	12	18	3	19.7%
D400S	Lts	112	224	336	$16.12	$16.12	$19.41	$19.41	2	4	5	2	4	7	1	20.4%
D400M	Lts	24	48	72	$16.19	$16.19	$19.46	$19.46	0	1	1	0	1	1	0	20.2%
D1000M	Lts	0	0	0	$25.52	$25.52	$26.55	$26.55	0	0	0	0	0	0	0	0.0%
Fuel Cost	MWH	1,603	4,482	6,085	$22.44	$22.44	$22.35	$22.35	36	101	137	36	100	136	-1	-0.4%
Riders	MWH	1,603	4,482	6,085	$2.47	$2.47	$1.31	$1.31	4	11	15	2	6	8	-7	-46.8%
Total:									350	731	1,081	417	865	1,282	201	18.6%
A07 Protective Ltg Sm C&I Secondary																
A100S	Lts	16,732	33,464	50,196	$7.34	$7.34	$8.99	$8.99	123	246	368	150	301	451	83	22.5%
A175M	Lts	6,800	13,600	20,400	$7.34	$7.34	$8.99	$8.99	50	100	150	61	122	183	34	22.5%
A250S	Lts	9,332	18,664	27,996	$11.64	$11.64	$14.45	$14.45	109	217	326	135	270	405	79	24.1%
A400M	Lts	3,868	7,736	11,604	$11.64	$11.64	$14.45	$14.45	45	90	135	56	112	168	33	24.1%
D250S	Lts	14,992	29,984	44,976	$12.62	$12.62	$15.10	$15.10	189	378	568	226	453	679	112	19.7%
D400S	Lts	20,312	40,624	60,936	$16.12	$16.12	$19.41	$19.41	327	655	982	394	789	1,183	200	20.4%
D400M	Lts	1,296	2,592	3,888	$16.19	$16.19	$19.46	$19.46	21	42	63	25	50	76	13	20.2%
D1000M	Lts	116	232	348	$25.52	$25.52	$26.55	$26.55	3	6	9	3	6	9	0	4.0%
Fuel Cost	MWH	5,908	17,128	23,036	$22.44	$22.44	$22.35	$22.35	133	384	517	132	383	515	-2	-0.4%
Riders	MWH	5,908	17,128	23,036	$2.47	$2.47	$1.31	$1.31	15	42	57	8	22	30	-27	-46.8%
Total:									1,014	2,161	3,175	1,191	2,508	3,699	524	16.5%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
		Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A30 St Ltg System Lighting Secondary																
OH70S	Lts	0	0	0	$9.63	$9.63	$13.32	$13.32	0	0	0	0	0	0	0	0.0%
OH100S	Lts	212	424	636	$10.17	$10.17	$13.92	$13.92	2	4	6	3	6	9	2	36.9%
OH150S	Lts	264	528	792	$10.95	$10.95	$14.94	$14.94	3	6	9	4	8	12	3	36.4%
OH200S	Lts	72	144	216	$12.88	$12.88	$16.84	$16.84	1	2	3	1	2	4	1	30.7%
OH250S	Lts	52	104	156	$13.87	$13.87	$17.97	$17.97	1	1	2	1	2	3	1	29.6%
OH400S	Lts	12	24	36	$16.85	$16.85	$21.54	$21.54	0	0	1	0	1	1	0	27.8%
OH175H	Lts	0	0	0	$14.98	$14.98	$18.38	$18.38	0	0	0	0	0	0	0	0.0%
OH40LED	Lts	204,912	409,824	614,736	$10.32	$10.32	$13.48	$13.48	2,115	4,229	6,344	2,762	5,524	8,287	1,943	30.6%
OH75LED	Lts	56,916	113,832	170,748	$11.01	$11.01	$14.19	$14.19	627	1,253	1,880	808	1,615	2,423	543	28.9%
OH165LED	Lts	11,044	22,088	33,132	$14.46	$14.46	$17.45	$17.45	160	319	479	193	385	578	99	20.7%
OH250LED	Lts	96	192	288	$17.98	$17.98	$20.96	$20.96	2	3	5	2	4	6	1	16.6%
UG70S	Lts	200	400	600	$19.54	$19.54	$24.12	$24.12	4	8	12	5	10	14	3	23.4%
UG100S	Lts	9,060	18,120	27,180	$20.07	$20.07	$24.71	$24.71	182	364	546	224	448	672	126	23.1%
UG150S	Lts	488	976	1,464	$20.86	$20.86	$25.74	$25.74	10	20	31	13	25	38	7	23.4%
UG250S	Lts	172	344	516	$23.38	$23.38	$28.53	$28.53	4	8	12	5	10	15	3	22.0%
UG400S	Lts	0	0	0	$26.06	$26.06	$31.93	$31.93	0	0	0	0	0	0	0	0.0%
UG175H	Lts	0	0	0	$27.90	$27.90	$32.66	$32.66	0	0	0	0	0	0	0	0.0%
UG40LED	Lts	75,828	151,656	227,484	$20.22	$20.22	$24.28	$24.28	1,533	3,066	4,600	1,841	3,682	5,523	924	20.1%
UG75LED	Lts	16,348	32,696	49,044	$20.91	$20.91	$24.98	$24.98	342	684	1,026	408	817	1,225	200	19.5%
UG165LED	Lts	3,636	7,272	10,908	$23.96	$23.96	$28.01	$28.01	87	174	261	102	204	306	44	16.9%
UG250LED	Lts	0	0	0	$27.19	$27.19	$31.34	$31.34	0	0	0	0	0	0	0	0.0%
Dec100S	Lts	280	560	840	$31.67	$31.67	$36.61	$36.61	9	18	27	10	21	31	4	15.6%
Dec150S	Lts	56	112	168	$32.84	$32.84	$37.87	$37.87	2	4	6	2	4	6	1	15.3%
Dec250S	Lts	216	432	648	$34.89	$34.89	$40.37	$40.37	8	15	23	9	17	26	4	15.7%
Dec400S	Lts	0	0	0	$37.38	$37.38	$43.66	$43.66	0	0	0	0	0	0	0	0.0%
PO70S	Lts	1,008	2,016	3,024	$5.97	$5.97	$6.56	$6.56	6	12	18	7	13	20	2	9.9%
PO100S	Lts	40,316	80,632	120,948	$6.66	$6.66	$7.34	$7.34	269	537	806	296	592	888	82	10.2%
PO150S	Lts	16,628	33,256	49,884	$7.54	$7.54	$8.35	$8.35	125	251	376	139	278	417	40	10.7%
PO250S	Lts	5,844	11,688	17,532	$9.61	$9.61	$10.70	$10.70	56	112	168	63	125	188	19	11.3%
PO400S	Lts	260	520	780	$12.42	$12.42	$13.90	$13.90	3	6	10	4	7	11	1	11.9%
PO175H	Lts	128	256	384	$13.54	$13.54	$14.91	$14.91	2	3	5	2	4	6	1	10.1%
PO40LED	Lts	2,432	4,864	7,296	$4.90	$4.90	$5.37	$5.37	12	24	36	13	26	39	3	9.6%
PO75LED	Lts	6,680	13,360	20,040	$5.49	$5.49	$6.03	$6.03	37	73	110	40	81	121	11	9.8%
PO165LED	Lts	2,292	4,584	6,876	$7.05	$7.05	$7.80	$7.80	16	32	48	18	36	54	5	10.6%
PO250LED	Lts	0	0	0	$8.93	$8.93	$9.92	$9.92	0	0	0	0	0	0	0	0.0%
POSurChg	Amt	39,188	78,377	117,565	$1.00	$1.00	$1.00	$1.00	39	78	118	39	78	118	0	0.0%
Fuel Cost	MWH	7,095	23,990	31,086	$22.44	$22.44	$22.35	$22.35	159	538	698	159	536	695	-3	-0.4%
Riders	MWH	7,095	23,990	31,086	$2.47	$2.47	$1.31	$1.31	18	59	77	9	31	41	-36	-46.8%
Total:									5,832	11,908	17,739	7,180	14,592	21,772	4,033	22.7%

Sales and Revenue by Rate Schedule and Component - Billing Units, Rates (Energy in Mills/kWh), and Revenues ($1,000's)

Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Revenues			Proposed Revenues			Increase	Pct Inc.
		Summer	Winter	Annual	Summer	Winter	Summer	Winter	Summer	Winter	Annual	Summer	Winter	Annual	Annual	Annual
A32 St Ltg Energy Lighting Secondary																
50S	Lts	15,364	30,728	46,092	$1.32	$1.32	$1.57	$1.57	20	41	61	24	48	72	12	18.9%
70S	Lts	49,980	99,960	149,940	$1.67	$1.67	$1.98	$1.98	83	167	250	99	198	297	46	18.6%
100S	Lts	40,724	81,448	122,172	$2.22	$2.22	$2.61	$2.61	90	181	271	106	213	319	48	17.6%
150S	Lts	18,220	36,440	54,660	$3.04	$3.04	$3.56	$3.56	55	111	166	65	130	195	28	17.1%
200S	Lts	5,988	11,976	17,964	$4.05	$4.05	$4.72	$4.72	24	49	73	28	57	85	12	16.5%
250S	Lts	23,212	46,424	69,636	$5.12	$5.12	$5.95	$5.95	119	238	357	138	276	414	58	16.2%
400S	Lts	3,784	7,568	11,352	$7.79	$7.79	$9.03	$9.03	29	59	88	34	68	103	14	15.9%
750S	Lts	184	368	552	$13.37	$13.37	$15.48	$15.48	2	5	7	3	6	9	1	15.8%
100M	Lts	308	616	924	$2.37	$2.37	$2.78	$2.78	1	1	2	1	2	3	0	17.3%
175M	Lts	2,276	4,552	6,828	$3.53	$3.53	$4.12	$4.12	8	16	24	9	19	28	4	16.7%
250M	Lts	380	760	1,140	$4.78	$4.78	$5.57	$5.57	2	4	5	2	4	6	1	16.5%
400M	Lts	1,332	2,664	3,996	$7.45	$7.45	$8.65	$8.65	10	20	30	12	23	35	5	16.1%
700M	Lts	216	432	648	$12.39	$12.39	$14.35	$14.35	3	5	8	3	6	9	1	15.8%
1000M	Lts	20	40	60	$17.24	$17.24	$19.95	$19.95	0	1	1	0	1	1	0	15.7%
1F72HO	Lts	36	72	108	$3.61	$3.61	$3.61	$3.61	0	0	0	0	0	0	0	0.0%
Fuel Cost	MWH	5,878	19,875	25,754	$22.44	$22.44	$22.35	$22.35	132	446	578	131	444	576	-2	-0.4%
Riders	MWH	5,878	19,875	25,754	$2.47	$2.47	$1.31	$1.31	14	49	64	8	26	34	-30	-46.8%
Total:									595	1,392	1,986	664	1,521	2,185	199	10.0%
A34 St Ltg Energy Mtrd Lighting Secondary																
Cust Chg	Bills	8,996	17,993	26,989	$5.00	$5.00	$5.50	$5.50	45	90	135	49	99	148	13	10.0%
Energy	MWH	8,032	27,156	35,187	$45.34	$45.34	$50.78	$50.78	364	1,231	1,595	408	1,379	1,787	191	12.0%
Fuel Cost	MWH	8,032	27,156	35,187	$22.44	$22.44	$22.35	$22.35	180	609	790	179	607	786	-3	-0.4%
Riders	MWH	8,032	27,156	35,187	$2.47	$2.47	$1.31	$1.31	20	67	87	11	36	46	-41	-46.8%
Total:									609	1,998	2,607	647	2,120	2,768	161	6.2%
A37 St Ltg St. Paul Lighting Secondary																
OH100S	Lts	4,308	8,616	12,924	$5.35	$5.35	$5.63	$5.63	23	46	69	24	49	73	4	5.2%
OH150S	Lts	2,376	4,752	7,128	$6.07	$6.07	$6.32	$6.32	14	29	43	15	30	45	2	4.1%
OH250S	Lts	4	8	12	$8.78	$8.78	$9.01	$9.01	0	0	0	0	0	0	0	2.6%
Fuel Cost	MWH	216	732	948	$22.44	$22.44	$22.35	$22.35	5	16	21	5	16	21	0	-0.4%
Riders	MWH	216	732	948	$2.47	$2.47	$1.31	$1.31	1	2	2	0	1	1	-1	-46.8%
Total:									43	93	136	44	96	140	4	3.1%
Retail + Interdepartmental Total:									1,191,943	1,877,495	3,069,438	1,377,610	2,156,501	3,534,111	464,673	15.1%
Interdepartmental without Base Increase:									350	386	736	335	369	704	-32	-4.3%
Retail:									1,191,593	1,877,109	3,068,702	1,377,275	2,156,132	3,533,407	464,705	15.1%

2020 Class Cost of Service Study Detail ($000)

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Rate Base											
	Plant In Service	Alloc	MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
1	Production		11,115,442	3,537,987	7,547,860	357,124	7,190,736	5,217,574	1,339,369	610,663	23,130	29,595
2	Transmission		3,268,599	1,251,302	2,017,041	110,987	1,906,054	1,423,528	341,202	130,219	11,106	256
3	Distribution		3,883,261	2,519,102	1,233,919	173,748	1,060,171	872,097	177,811	10,029	234	130,240
4	General		1,691,167	676,603	999,743	59,423	940,321	695,564	172,047	69,518	3,191	14,821
5	Common		0	0	0	0	0	0	0	0	0	0
6	Total Plant In Service		19,958,469	7,984,995	11,798,563	701,282	11,097,282	8,208,763	2,030,429	820,429	37,661	174,911
7	Production		6,326,757	2,006,203	4,303,410	203,051	4,100,359	2,973,651	764,199	349,326	13,182	17,145
8	Transmission		728,387	279,289	449,066	24,734	424,332	316,760	75,826	28,851	2,896	32
9	Distribution		1,446,041	962,647	450,060	66,314	383,745	318,111	61,772	3,766	96	33,334
10	General		794,234	317,757	469,516	27,907	441,609	326,662	80,800	32,648	1,499	6,960
11	Common		0	0	0	0	0	0	0	0	0	0
12	Total Depreciation Reserve		9,295,420	3,565,897	5,672,051	322,007	5,350,045	3,935,185	982,596	414,591	17,673	57,471
13	**Net Plant In Service**		10,663,050	4,419,098	6,126,512	379,275	5,747,237	4,273,578	1,047,833	405,838	19,988	117,440
14	Deducts: Accum Defer Inc Tax		2,301,002	950,124	1,327,014	82,279	1,244,736	926,452	226,583	87,229	4,472	23,864
15	Constr Work In Progress		363,989	132,680	229,544	12,356	217,187	159,072	40,324	17,124	667	1,765
16	Fuel Inventory		65,875	19,715	45,935	2,080	43,854	31,563	8,244	3,908	140	225
17	Materials & Supplies		153,932	52,423	100,843	5,072	95,771	69,820	17,762	7,877	312	666
18	Prepayments		99,733	41,332	57,302	3,547	53,754	39,971	9,800	3,796	187	1,098
19	Non-Plant & Work Cash		(58,674)	(26,968)	(31,069)	(2,049)	(29,020)	(21,890)	(5,212)	(1,802)	(115)	(638)
20	Total Additions		624,853	219,183	402,554	21,006	381,547	278,537	70,918	30,902	1,191	3,116
21	**Rate Base**		8,986,901	3,688,157	5,202,051	318,003	4,884,049	3,625,663	892,167	349,511	16,707	96,692
	Income Statement											
22A	**Tot Oper Rev - Pres**		3,666,158	1,353,685	2,284,375	127,412	2,156,964	1,612,079	374,326	163,268	7,290	28,097
22B	**Tot Oper Rev - Prop**		3,867,585	1,442,171	2,394,339	135,943	2,258,396	1,687,576	393,502	169,797	7,521	31,075
23	Oper & Maint		2,357,626	833,748	1,509,566	81,590	1,427,977	1,046,075	263,627	113,794	4,481	14,312
24	Book Depr + IRS Int		683,392	269,402	406,126	23,845	382,280	282,320	70,001	28,701	1,258	7,865
25	Payroll, Rl Est & Prop Tax		205,616	86,701	116,777	7,448	109,329	81,407	19,873	7,680	369	2,138
26	Deferred Inc Tax & Net ITC		(71,438)	(34,884)	(35,298)	(2,716)	(32,581)	(24,783)	(5,789)	(1,908)	(101)	(1,256)
27A	Present Income Tax		(6,184)	1,940	(8,511)	(77)	(8,434)	1,975	(8,187)	(2,293)	70	388
27B	Proposed Income Tax		51,710	27,372	23,094	2,375	20,720	23,675	(2,675)	(416)	136	1,244
28	Allow Funds Dur Const		28,846	10,486	18,225	973	17,252	12,627	3,209	1,360	57	135
29A	**Present Return**		525,991	207,265	313,941	18,296	295,645	237,712	38,009	18,653	1,271	4,785
29B	**Proposed Return**		669,524	270,318	392,298	24,375	367,923	291,509	51,673	23,306	1,435	6,908
30A	**Pres Ret on Rt Base**		5.85%	5.62%	6.03%	5.75%	6.05%	6.56%	4.26%	5.34%	7.61%	4.95%
30B	**Prop Ret on Rt Base**		**7.45%**	7.33%	7.54%	7.67%	7.53%	8.04%	5.79%	6.67%	8.59%	7.14%
31A	**Pres Ret on Common**		7.17%	6.72%	7.51%	6.98%	7.55%	8.51%	4.13%	6.18%	10.51%	5.45%
31B	**Prop Ret on Common**		**10.21%**	9.98%	10.38%	10.62%	10.37%	11.33%	7.05%	8.72%	12.38%	9.63%

Northern States Power Company

2020 Class Cost of Service Study Detail ($000)

PRES vs Equal Rev Reqts

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	**UnAdj Equal Rev Reqt @ 7.45%**		**3,320,983**	**1,260,019**	**2,030,865**	**116,903**	**1,913,962**	**1,409,764**	**351,770**	**146,266**	**6,162**	**30,098**
2	**Present Revenue**		**3,120,405**	**1,165,785**	**1,927,911**	**109,370**	**1,818,541**	**1,364,535**	**311,884**	**135,923**	**6,199**	**26,709**
3	**UnAdj Revenue Deficiency**		**200,578**	**94,234**	**102,954**	**7,534**	**95,421**	**45,229**	**39,886**	**10,343**	**(38)**	**3,389**
4	**UnAdj Deficiency / Present**		**6.43%**	**8.08%**	**5.34%**	**6.89%**	**5.25%**	**3.31%**	**12.79%**	**7.61%**	**-0.61%**	**12.69%**
			[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS									
5	**Pres Int Rate Discounts**											
6	**Pres Econ Dvlp Rate Discounts**											
7	**Pres Int Rate Disc Cost Alloc**	**D10S**										
8	**Pres Econ Dvlp Disc Cost Alloc**	**R01**										
										HIGHLY CONFIDENTIAL TRADE SECRET ENDS]		
9	**Revenue Requirement Shift**		**0**	**(1,893)**	**1,889**	**1,447**	**442**	**9,932**	**(2,346)**	**(6,894)**	**(251)**	**4**
10	**Adj Equal Rev Reqt (Rows 1+9)**		**3,320,983**	**1,258,126**	**2,032,754**	**118,350**	**1,914,404**	**1,419,696**	**349,424**	**139,373**	**5,911**	**30,102**
11	**Adj Rev Defic vs Pres Rev (Row 2)**		**200,578**	**92,342**	**104,844**	**8,981**	**95,863**	**55,162**	**37,540**	**3,449**	**(288)**	**3,392**
12	**Adj Deficiency / Adj Present**		**6.43%**	**7.92%**	**5.44%**	**8.21%**	**5.27%**	**4.04%**	**12.04%**	**2.54%**	**-4.65%**	**12.70%**
	Equal Customer Classification											
13	Min Sys & Service Drop		226,596	183,765	20,709	12,313	8,395	8,231	176	(14)	2	22,123
14	Energy Services		61,570	51,157	10,136	5,692	4,444	4,376	64	2	1	278
15	Total Customer **(Cusco)**		288,167	234,922	30,844	18,005	12,839	12,607	240	(12)	4	22,401
16	Ave Monthly Customers		1,334,596	1,170,186	136,525	87,750	48,776	48,273	479	15	9	27,884
17	Svc Drop Reqt	$ / Mo / Cust	$14.15	$13.09	$12.64	$11.69	$14.34	$14.21	$30.66	($79.79)	$19.78	$66.12
18	Ener Svcs Reqt	$ / Mo / Cust	$3.84	$3.64	$6.19	$5.41	$7.59	$7.55	$11.09	$13.80	$13.06	$0.83
19	Total Reqt	$ / Mo / Cust	$17.99	$16.73	$18.83	$17.10	$21.94	$21.76	$41.75	($65.99)	$32.84	$66.95
	Equal Energy Classification											
20	On Peak Rev Reqt		803,816	230,873	571,620	29,495	542,125	396,195	100,388	43,806	1,736	1,323
21	Off Peak Rev Reqt		808,386	251,255	552,827	21,298	531,529	379,481	100,792	49,537	1,719	4,304
22	Total Ener Rev Reqt		1,612,202	482,128	1,124,447	50,792	1,073,654	775,676	201,180	93,343	3,455	5,627
23	Annual MWh Sales		28,838,346.945	8,450,856	20,264,816	853,252	19,411,564	13,765,907	3,724,793	1,856,137	64,727	122,675
24	On Pk Reqt	Mills / kWh	27.873	27.320	28.208	34.567	27.928	28.781	26.951	23.601	26.818	10.783
25	Off Pk Reqt	Mills / kWh	28.032	29.731	27.280	24.960	27.382	27.567	27.060	26.688	26.557	35.085
26	Total Reqt	Mills / kWh	55.905	57.051	55.488	59.528	55.310	56.348	54.011	50.289	53.374	45.868
	Equal Demand Classification											
27	Energy-Related Prod		345,115	106,178	237,880	10,976	226,905	163,940	42,462	19,775	727	1,056
28	Capacity-Related Summer Peak Prod		293,753	112,975	180,778	9,998	170,780	127,974	30,628	11,611	567	0
29	Capacity-Related Winter Peak Prod		88,784	34,146	54,638	3,022	51,617	38,679	9,257	3,509	171	0
30	Total Capacity-Related Prod		382,537	147,121	235,416	13,020	222,396	166,653	39,885	15,120	739	0
31	Total Production		727,652	253,299	473,297	23,996	449,301	330,593	82,347	34,895	1,466	1,056
32	Transmission **(Transco)**		429,619	165,071	264,548	14,608	249,940	187,027	44,739	16,960	1,215	0
33	Primary Dist Subs		83,986	34,131	49,407	3,297	46,110	36,155	8,852	1,080	23	448
34	Prim Dist Lines		151,561	75,452	75,599	5,282	70,318	55,906	14,412	0	0	509
35	Second Dist, Trans		27,795	15,014	12,723	923	11,800	11,800	0	0	0	58
36	Total Distribution **(Disco)**		263,343	124,598	137,730	9,502	128,227	103,861	23,264	1,080	23	1,015
37	Total Demand Rev Reqt		1,420,614	542,969	875,574	48,106	827,469	621,481	150,350	52,935	2,703	2,071
38	Annual Billing kW		50,585,647	0	50,585,647	0	50,585,647	38,601,454	8,076,778	3,687,056	220,358	0
39	Base Rev Reqt	$ / kW	$0.00	$0.00	$4.70	$0.00	$4.49	$4.25	$5.26	$5.36	$3.30	$0.00
40	Summer Rev Reqt	$ / kW	$0.00	$0.00	$3.57	$0.00	$3.38	$3.32	$3.79	$3.15	$2.57	$0.00
41	Winter Rev Reqt	$ / kW	$0.00	$0.00	$1.08	$0.00	$1.02	$1.00	$1.15	$0.95	$0.78	$0.00
42	Prod Rev Reqt	$ / kW	$0.00	$0.00	$9.36	$0.00	$8.88	$8.56	$10.20	$9.46	$6.65	$0.00
43	Tran Rev Reqt	$ / kW	$0.00	$0.00	$5.23	$0.00	$4.94	$4.85	$5.54	$4.60	$5.51	$0.00
44	Dist Rev Reqt	$ / kW	$0.00	$0.00	$2.72	$0.00	$2.53	$2.69	$2.88	$0.29	$0.10	$0.00
45	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$17.31	$0.00	$16.36	$16.10	$18.62	$14.36	$12.27	$0.00
46	Tot Dmd Rev Reqt	Mills / kWh	49.261	64.250	43.207	56.379	42.628	45.146	40.365	28.519	41.766	16.882
47	Summer Billing kW		18,568,179	0	18,568,179	0	18,568,179	14,099,351	3,037,682	1,342,582	88,563	0
48	Winter Billing kW		32,017,467	0	32,017,467	0	32,017,467	24,502,103	5,039,096	2,344,474	131,795	0
49	Tot Summer Reqt	$ / kW	$0.00	$0.00	$22.39	$0.00	$21.16	$20.86	$23.76	$18.90	$15.32	$0.00
50	Tot Winter Reqt	$ / kW	$0.00	$0.00	$14.36	$0.00	$13.57	$13.36	$15.51	$11.75	$10.22	$0.00
51	Energy + Production **(Genco)**		2,339,854	735,428	1,597,744	74,788	1,522,956	1,106,269	283,528	128,238	4,921	6,683

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

Northern States Power Company

2020 Class Cost of Service Study Detail ($000)

PROP vs Equal Rev Reqts

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Total Retail Rev Reqt	Alloc	MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
1	**Proposed Ret On Rt Base**		**7.45%**	**7.33%**	**7.54%**	**7.67%**	**7.53%**	**8.04%**	**5.79%**	**6.67%**	**8.59%**	**7.14%**
2	**UnAdj Equalized Rev Reqt**		**3,320,983**	**1,260,019**	**2,030,865**	**116,903**	**1,913,962**	**1,409,764**	**351,770**	**146,266**	**6,162**	**30,098**
3	**Proposed Revenue**		**3,320,983**	**1,253,775**	**2,037,525**	**117,863**	**1,919,662**	**1,439,792**	**331,010**	**142,431**	**6,429**	**29,683**
4	**UnAdj Revenue Deficiency**		**(0)**	**6,244**	**(6,660)**	**(960)**	**(5,700)**	**(30,028)**	**20,760**	**3,835**	**(267)**	**415**
5	**UnAdj Deficiency / Proposed**		**0.00%**	**0.50%**	**-0.33%**	**-0.81%**	**-0.30%**	**-2.09%**	**6.27%**	**3%**	**-4%**	**1.40%**
			[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS									
6	**Prop Interrupt Rate Discounts**											
7	**Prop Econ Dev Rate Discounts**											
8	**Prop Int Rate Disc Cost Alloc**	**D10S**										
9	**Prop ED Discount Cost Alloc**	**R01**										
												HIGHLY CONFIDENTIAL TRADE SECRET ENDS]
10	**Revenue Requirement Shift**		**0**	**3,390**	**(3,394)**	**1,687**	**(5,081)**	**7,247**	**(4,225)**	**(7,807)**	**(296)**	**4**
11	**Adj Equal Rev (Rows 2+10)**		**3,320,983**	**1,263,409**	**2,027,472**	**118,590**	**1,908,881**	**1,417,011**	**347,545**	**138,459**	**5,866**	**30,102**
12	**Adj Rev Defic vs Prop Rev (Row 3)**		**(0)**	**9,634**	**(10,053)**	**727**	**(10,781)**	**(22,781)**	**16,535**	**(3,972)**	**(563)**	**419**
13	**Adj Deficiency / Adj Prop**		**0.00%**	**0.77%**	**-0.49%**	**0.62%**	**-0.56%**	**-1.58%**	**5.00%**	**-2.79%**	**-8.76%**	**1.41%**
	Prop Customer Component											
14	Min Sys & Service Drop		223,554	180,950	20,895	12,356	8,539	8,384	167	(14)	2	21,709
15	Energy Services		61,564	51,150	10,136	5,692	4,444	4,377	64	2	1	278
16	Total Customer **(Cusco)**		285,118	232,100	31,031	18,048	12,983	12,760	231	(12)	4	21,987
17	Ave Monthly Customers		1,334,596	1,170,186	136,525	87,750	48,776	48,273	479	15	9	27,884
18	Svc Drop Reqt	$ / Mo / Cust	$13.96	$12.89	$12.75	$11.73	$14.59	$14.47	$29.12	($80.21)	$20.16	$64.88
19	Ener Svcs Reqt	$ / Mo / Cust	$3.84	$3.64	$6.19	$5.41	$7.59	$7.56	$11.08	$13.79	$13.06	$0.83
20	Total Reqt	$ / Mo / Cust	$17.80	$16.53	$18.94	$17.14	$22.18	$22.03	$40.21	($66.42)	$33.22	$65.71
	Prop Energy Component											
21	On Peak Rev Reqt		803,628	230,805	571,501	29,493	542,008	396,265	100,239	43,768	1,737	1,322
22	Off Peak Rev Reqt		808,182	251,180	552,699	21,296	531,403	379,548	100,642	49,493	1,720	4,303
23	Total Ener Rev Reqt		1,611,810	481,984	1,124,200	50,789	1,073,412	775,814	200,880	93,261	3,457	5,625
24	Annual MWh Sales		28,838,347	8,450,856	20,264,816	853,252	19,411,564	13,765,907	3,724,793	1,856,137	64,727	122,675
25	On Pk Reqt	Mills / kWh	27.867	27.311	28.202	34.565	27.922	28.786	26.911	23.580	26.833	10.780
26	Off Pk Reqt	Mills / kWh	28.025	29.722	27.274	24.959	27.376	27.572	27.019	26.665	26.572	35.073
27	Total Reqt	Mills / kWh	55.891	57.034	55.475	59.524	55.298	56.358	53.931	50.245	53.405	45.853
	Prop Demand Component											
28	Energy-Related Prod		353,583	107,570	244,948	11,627	233,321	181,945	32,771	17,738	867	1,065
29	Capacity-Related Summer Peak Prod		292,994	112,244	180,750	10,060	170,690	130,473	28,447	11,179	591	0
30	Capacity-Related Winter Peak Prod		88,555	33,925	54,630	3,041	51,589	39,434	8,598	3,379	179	0
31	Total Capacity-Related Prod		381,548	146,168	235,380	13,100	222,279	169,908	37,044	14,557	770	0
32	Total Production		735,131	253,738	480,328	24,728	455,600	351,852	69,816	32,295	1,637	1,065
33	Transmission **(Transco)**		425,900	162,562	263,338	14,691	248,647	192,233	39,267	15,840	1,306	0
34	Primary Dist Subs		85,027	34,300	50,278	3,381	46,897	37,854	7,972	1,046	25	449
35	Prim Dist Lines		150,171	74,334	75,336	5,301	70,035	57,191	12,844	0	0	501
36	Second Dist, Trans		27,826	14,757	13,013	925	12,088	12,088	0	0	0	56
37	Total Distribution **(Disco)**		263,024	123,390	138,628	9,607	129,020	107,133	20,816	1,046	25	1,006
38	Total Demand Rev Reqt		1,424,055	539,691	882,294	49,026	833,268	651,218	129,899	49,182	2,969	2,071
39	Annual Billing kW		50,585,647	0	50,585,647	0	50,585,647	38,601,454	8,076,778	3,687,056	220,358	0
40	Base Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$4.61	$4.71	$4.06	$4.81	$3.94	$0.00
41	Summer Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$3.37	$3.38	$3.52	$3.03	$2.68	$0.00
42	Winter Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$1.02	$1.02	$1.06	$0.92	$0.81	$0.00
43	Prod Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$9.01	$9.11	$8.64	$8.76	$7.43	$0.00
44	Tran Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$4.92	$4.98	$4.86	$4.30	$5.93	$0.00
45	Dist Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$2.55	$2.78	$2.58	$0.28	$0.12	$0.00
46	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$16.47	$16.87	$16.08	$13.34	$13.47	$0.00
47	Tot Dmd Rev Reqt	Mills / kWh	49.381	63.862	43.538	57.458	42.926	47.307	34.874	26.497	45.864	16.880
48	Summer Billing kW		18,568,179	0	18,568,179	0	18,568,179	14,099,351	3,037,682	1,342,582	88,563	0
49	Winter Billing kW		32,017,467	0	32,017,467	0	32,017,467	24,502,103	5,039,096	2,344,474	131,795	0
50	Tot Summer Reqt	$ / kW	$0.00	$0.00	$22.52	$0.00	$21.27	$21.72	$20.86	$17.72	$16.65	$0.00
51	Tot Winter Reqt	$ / kW	$0.00	$0.00	$14.49	$0.00	$13.69	$14.08	$13.20	$10.83	$11.33	$0.00
52	Energy + Production **(Genco)**		2,346,941	735,723	1,604,528	75,516	1,529,012	1,127,666	270,696	125,556	5,094	6,690
53	Prop Rev - Pres Rev (Pg 2)		200,578	87,990	109,614	8,493	101,121	75,257	19,126	6,508	230	2,974
54	Difference / Present		6.43%	7.55%	5.69%	7.77%	5.56%	5.52%	6.13%	4.79%	3.71%	11.13%

2020 Class Cost of Service Study Detail ($000) — Page 4 of 14

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

Original Plant in Service

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Summer Peak	D10S		1,882,738	725,755	1,156,983	64,150	1,092,833	818,949	195,973	74,281	3,630	0
2	WInter Peak	D10S		569,040	219,353	349,687	19,389	330,299	247,519	59,231	22,451	1,097	0
3	Total Peak	D10S		2,451,778	945,108	1,506,670	83,538	1,423,132	1,066,468	255,204	96,732	4,727	0
4	Base Load	E8760		6,231,510	1,864,979	4,345,244	196,782	4,148,462	2,985,764	779,807	369,654	13,236	21,287
5	Nuclear Fuel	E8760		2,432,155	727,900	1,695,946	76,804	1,619,142	1,165,342	304,358	144,276	5,166	8,308
6	Total	28.24%	120, 310-346	11,115,442	3,537,987	7,547,860	357,124	7,190,736	5,217,574	1,339,369	610,663	23,130	29,595
	Transmission												
7	Gen Step Up Base	E8760		74,843	22,399	52,188	2,363	49,825	35,860	9,366	4,440	159	256
8	Gen Step Up Peak	D10S		31,607	12,184	19,423	1,077	18,346	13,748	3,290	1,247	61	0
9	Total Gen Step Up			106,450	34,583	71,611	3,440	68,171	49,609	12,656	5,687	220	256
10	Bulk Transmission	D10S		3,156,387	1,216,719	1,939,668	107,546	1,832,121	1,372,957	328,546	124,532	6,086	0
11	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign		5,762	0	5,762	0	5,762	962	0	0	4,800	0
13	Total		350-359	3,268,599	1,251,302	2,017,041	110,987	1,906,054	1,423,528	341,202	130,219	11,106	256
	Distribution:												
	Substations												
14	Generat Step Up	STRATH		3,046	957	2,081	97	1,984	1,437	370	170	6	9
15	Bulk Transmission	D10S		1,655	638	1,017	56	960	720	172	65	3	0
16	Distrib Function	D60Sub		658,942	274,306	381,049	26,469	354,581	289,158	65,365	58	0	3,586
17	Direct Assign	Dir Assign		16,505.484	0	16,505	0	16,505	372	6,225	9,703	206	0
18	Total		360-363	680,148	275,901	400,653	26,623	374,030	291,685	72,132	9,997	215	3,595
	Overhead Lines												
19	Primary Capacity 1 Phase	D61PS1Ph		143,947	107,145	36,294	5,345	30,949	22,635	8,314	0	0	509
20	Primary Capacity Multi Phase	D61PS		309,713	113,372	195,332	10,421	184,911	149,306	35,605	0	0	1,009
21	Primary Customer 1 Phase	C61PS1Ph		77,221	73,544	3,491	2,995	496	488	7	0	0	186
22	Primary Customer Multi Phase	C61PS		166,146	148,137	17,308	11,117	6,191	6,130	61	0	0	701
23	Total Primary			697,027	442,198	252,425	29,879	222,547	178,559	43,988	0	0	2,404
24	Second Capacity	D62SecL		35,425	17,481	17,853	1,282	16,572	16,572	0	0	0	90
25	Second Customer	C62Sec		127,454	113,681	13,236	8,532	4,704	4,704	0	0	0	538
26	Total Secondary			162,879	131,162	31,089	9,813	21,276	21,276	0	0	0	628
27	Street Lighting	DASL		42,578	0	0	0	0	0	0	0	0	42,578
28	Total		364,365	902,484	573,360	283,514	39,692	243,823	199,835	43,988	0	0	45,610
	Underground Lines												
29	Primary Capacity 1 Phase	D61PS1Ph		247,789	184,437	62,476	9,200	53,276	38,964	14,312	0	0	876
30	Primary Capacity Multi Phase	D61PS		356,138	130,366	224,612	11,983	212,629	171,687	40,943	0	0	1,160
31	Primary Customer 1 Phase	C61PS1Ph		281,596	268,189	12,730	10,923	1,807	1,780	27	0	0	677
32	Primary Customer Multi Phase	C61PS		404,727	360,858	42,162	27,082	15,080	14,932	148	0	0	1,707
33	Total Primary			1,290,250	943,850	341,980	59,188	282,792	227,362	55,430	0	0	4,420
34	Second Capacity	D62SecL		41,508	20,483	20,919	1,502	19,418	19,418	0	0	0	106
35	Second Customer	C62Sec		116,691	104,081	12,118	7,811	4,307	4,307	0	0	0	492
36	Total Secondary			158,199	124,564	33,037	9,313	23,725	23,725	0	0	0	598
37	Street Lighting	DASL		0	0	0	0	0	0	0	0	0	0
38	Total		366,367	1,448,449	1,068,413	375,017	68,501	306,517	251,087	55,430	0	0	5,018
	Line Transformers												
39	Primary	D61PS		44,017	16,112	27,761	1,481	26,280	21,219	5,060	0	0	143
40	Second Capacity	D62SecL		131,409	64,846	66,227	4,754	61,473	61,473	0	0	0	335
41	Second Customer	C62Sec		230,769	205,831	23,964	15,447	8,517	8,517	0	0	0	974
42	Total		368	406,195	286,790	117,953	21,682	96,270	91,210	5,060	0	0	1,452
	Services												
43	Second Capacity	D62NLL		63,801	47,500	16,300	1,316	14,984	14,984	0	0	0	0
44	Second Customer	C62NL		220,538	209,265	11,273	7,266	4,006	4,006	0	0	0	0
43	Total Services	C62NL	369	284,339	256,766	27,573	8,582	18,990	18,990	0	0	0	0
44	Meters	C12WM	370	87,270	57,873	29,210	8,668	20,541	19,289	1,200	33	19	188
45	Street Lighting	Dir Assign	373	74,377	0	0	0	0	0	0	0	0	74,377
46	**Total Distribution**			3,883,261	2,519,102	1,233,919	173,748	1,060,171	872,097	177,811	10,029	234	130,240
47	**General & Common Plant**	PTD	303, 389-399	1,691,167	676,603	999,743	59,423	940,321	695,564	172,047	69,518	3,191	14,821
48	Prelim Elec Plant			19,958,469	7,984,995	11,798,563	701,282	11,097,282	8,208,763	2,030,429	820,429	37,661	174,911
49	TBT Investment	NEPIS		0	0	0	0	0	0	0	0	0	0
50	**Elec Plant in Serv**			19,958,469	7,984,995	11,798,563	701,282	11,097,282	8,208,763	2,030,429	820,429	37,661	174,911

2020 Class Cost of Service Study Detail ($000) Page 5 of 14

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

Accum Deprec; Net Plant

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		1,307,680	504,082	803,597	44,556	759,041	568,811	136,116	51,593	2,521	0
2	Decom Int Peaking	D10S		0	0	0	0	0	0	0	0	0	0
3	Decom Int Baseload	E8760		0	0	0	0	0	0	0	0	0	0
4	Nuclear Fuel	E8760		2,255,886	675,146	1,573,033	71,238	1,501,796	1,080,885	282,300	133,820	4,792	7,706
5	Base Load	E8760		2,763,192	826,974	1,926,779	87,258	1,839,521	1,323,955	345,784	163,913	5,869	9,439
6	Total		108,111,115,120.5	6,326,757	2,006,203	4,303,410	203,051	4,100,359	2,973,651	764,199	349,326	13,182	17,145
	Transmission												
7	Gen Step Up Base	E8760		9,251	2,769	6,451	292	6,159	4,433	1,158	549	20	32
8	Gen Step Up Peak	D10S		13,453	5,186	8,267	458	7,809	5,852	1,400	531	26	0
9	Total Gen Step Up			22,704	7,954	14,718	751	13,967	10,284	2,558	1,080	46	32
10	Bulk Transmission	D10S		703,891	271,335	432,556	23,983	408,573	306,177	73,268	27,771	1,357	0
11	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign		1,792	0	1,792	0	1,792	299	0	0	1,493	0
13	Total		108,111,115,120.5	728,387	279,289	449,066	24,734	424,332	316,760	75,826	28,851	2,896	32
	Distribution												
14	Generat Step Up	STRATH		2,185	686	1,493	70	1,423	1,030	266	122	5	6
15	Bulk Transmission	D10S		629	243	387	21	365	274	65	25	1	0
16	Distrib Function	D60Sub		226,935	94,469	131,231	9,116	122,115	99,584	22,511	20	0	1,235
17	Direct Assign	Dir Assign		6,080	0	6,080	0	6,080	137	2,293	3,574	76	0
18	Total Substations			235,828	95,398	139,189	9,207	129,982	101,025	25,135	3,741	82	1,241
19	Overhead Lines	POL		332,610	211,311	104,489	14,628	89,861	73,649	16,212	0	0	16,809
20	Underground	PUL		453,955	334,849	117,533	21,469	96,065	78,693	17,372	0	0	1,573
21	Line Transformers	P68		170,728	120,541	49,577	9,113	40,463	38,337	2,127	0	0	610
22	Services	P69		172,656	155,913	16,743	5,211	11,531	11,531	0	0	0	0
23	Meters	C12WM		67,309	44,636	22,529	6,686	15,843	14,877	926	25	15	145
24	Street Lighting	P73		12,956	0	0	0	0	0	0	0	0	12,956
25	Total		108,111,115,120.5	1,446,041	962,647	450,060	66,314	383,745	318,111	61,772	3,766	96	33,334
26	**General & CommonPlant**	PTD	108,111,115,120.5	794,234	317,757	469,516	27,907	441,609	326,662	80,800	32,648	1,499	6,960
27	**Total Accum Depr**			9,295,420	3,565,897	5,672,051	322,007	5,350,045	3,935,185	982,596	414,591	17,673	57,471
28	**Net Elec Plant**			10,663,050	4,419,098	6,126,512	379,275	5,747,237	4,273,578	1,047,833	405,838	19,988	117,440
29	**Net Plant w/ TBT**			10,663,050	4,419,098	6,126,512	379,275	5,747,237	4,273,578	1,047,833	405,838	19,988	117,440

Subtractions: Accum Defer Inc Tax

				MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
	Production												
30	Peaking Plant	D10S		272,266	104,953	167,313	9,277	158,036	118,429	28,340	10,742	525	0
31	Base Load	E8760		896,139	268,198	624,879	28,299	596,581	429,376	112,142	53,159	1,903	3,061
32	Nuclear Fuel	E8760		2,752	824	1,919	87	1,832	1,319	344	163	6	9
33	Total		190,281,282,283	1,171,157	373,975	794,112	37,662	756,449	549,124	140,827	64,064	2,434	3,071
	Transmission												
34	Gen Step Up Base	E8760		14,581	4,364	10,168	460	9,707	6,987	1,825	865	31	50
35	Gen Step Up Peak	D10S		3,862	1,489	2,373	132	2,242	1,680	402	152	7	0
36	Total Gen Step Up			18,444	5,853	12,541	592	11,949	8,666	2,227	1,017	38	50
37	Bulk Transmission	D10S		698,010	269,068	428,942	23,783	405,159	303,618	72,655	27,539	1,346	0
38	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
39	Direct Assign	Dir Assign		1,181	0	1,181	0	1,181	197	0	0	984	0
40	Total		281,282,283	717,634	274,920	442,664	24,375	418,289	312,482	74,882	28,557	2,368	50
	Distribution												
41	Generat Step Up	STRATH		351	110	240	11	229	166	43	20	1	1
42	Bulk Transmission	D10S		255	98	157	9	148	111	27	10	0	0
43	Distrib Function	D60Sub		110,245	45,893	63,752	4,428	59,323	48,378	10,936	10	0	600
44	Direct Assign	Dir Assign		2,278	0	2,278	0	2,278	51	859	1,339	28	0
45	Total Substations			113,129	46,102	66,427	4,448	61,979	48,706	11,864	1,379	30	601
46	Overhead Lines	POL		149,814	95,179	47,064	6,589	40,475	33,173	7,302	0	0	7,571
47	Underground	PUL		237,803	175,410	61,570	11,246	50,323	41,223	9,100	0	0	824
48	Line Transformers	P68		58,672	41,424	17,037	3,132	13,905	13,175	731	0	0	210
49	Services	P69		19,940	18,006	1,934	602	1,332	1,332	0	0	0	0
50	Meters	C12WM		10,815	7,172	3,620	1,074	2,545	2,390	149	4	2	23
51	Street Lighting	P73		13,969	0	0	0	0	0	0	0	0	13,969
52	Total		281,282,283	604,142	383,293	197,651	27,091	170,560	139,998	29,147	1,383	32	23,198
53	**General & Common Plant**	PTD	281,282,283	141,401	56,572	83,590	4,968	78,622	58,157	14,385	5,813	267	1,239
54	**Total Deferred Tax**			2,634,334	1,088,760	1,518,017	94,097	1,423,919	1,059,761	259,240	99,816	5,101	27,557
55	Net Operating Loss (NOL) Carry F	NEPIS		(356,731)	(147,841)	(204,962)	(12,689)	(192,273)	(142,972)	(35,055)	(13,577)	(669)	(3,929)
56	Non-Plant Related	LABOR		23,399	9,204	13,959	870	13,089	9,663	2,398	990	39	235
57	**Accum Def W/ Adj**			2,301,002	950,124	1,327,014	82,279	1,244,736	926,452	226,583	87,229	4,472	23,864

Northern States Power Company

2020 Class Cost of Service Study Detail ($000)

Additions: CWIP, Etc; Rate Base

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		21,948	8,461	13,488	748	12,740	9,547	2,285	866	42	0
2	Base Load	E8760		75,043	22,459	52,328	2,370	49,958	35,956	9,391	4,452	159	256
3	Nuclear Fuel	E8760		124,525	37,268	86,831	3,932	82,899	59,665	15,583	7,387	265	425
4	Total		107	221,516	68,188	152,647	7,050	145,597	105,168	27,258	12,704	466	682
	Transmission												
5	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10S		2,097	808	1,289	71	1,217	912	218	83	4	0
7	Total Gen Step Up			2,097	808	1,289	71	1,217	912	218	83	4	0
8	Bulk Transmission	D10S		42,172	16,256	25,915	1,437	24,479	18,344	4,390	1,664	81	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
11	Total		107	44,269	17,065	27,204	1,508	25,696	19,256	4,608	1,747	85	0
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub		12,998	5,411	7,516	522	6,994	5,704	1,289	1	0	71
15	Direct Assign	Dir Assign		491	0	491	0	491	11	185	289	6	0
16	Total Substations			13,488	5,411	8,007	522	7,485	5,715	1,474	290	6	71
17	Overhead Lines	POL		8,747	5,557	2,748	385	2,363	1,937	426	0	0	442
18	Underground	PUL		16,926	12,485	4,382	800	3,582	2,934	648	0	0	59
19	Line Transformers	P68		928	655	270	50	220	208	12	0	0	3
20	Services	P69		138	125	13	4	9	9	0	0	0	0
21	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
23	Total		107	40,228	24,233	15,420	1,761	13,659	10,803	2,560	290	6	575
24	**General & Common Plant**	PTD	107	57,977	23,195	34,273	2,037	32,236	23,845	5,898	2,383	109	508
25	**Total CWIP**			363,989	132,680	229,544	12,356	217,187	159,072	40,324	17,124	667	1,765
26	Fuel Inventory	E8760	151,152	65,875	19,715	45,935	2,080	43,854	31,563	8,244	3,908	140	225
	Materials & Supplies												
27	Production	P10		137,523	43,773	93,384	4,418	88,965	64,553	16,571	7,555	286	366
28	Trans & Distr	TD		16,409	8,651	7,459	653	6,806	5,267	1,191	322	26	299
29	Total		154	153,932	52,423	100,843	5,072	95,771	69,820	17,762	7,877	312	666
	Prepayments												
30	Miscellaneous	NEPIS		99,733	41,332	57,302	3,547	53,754	39,971	9,800	3,796	187	1,098
31	Fuel	E8760		0	0	0	0	0	0	0	0	0	0
32	Insurance	NEPIS	135,143,184,186,232	0	0	0	0	0	0	0	0	0	0
33	Total		235,252,165	99,733	41,332	57,302	3,547	53,754	39,971	9,800	3,796	187	1,098
34	Non-Plant Assets & Liab	LABOR	190,283,	60,475	23,789	36,078	2,249	33,829	24,973	6,198	2,558	101	608
35	Working Cash	PT0	calculated	(119,149)	(50,756)	(67,147)	(4,298)	(62,849)	(46,863)	(11,410)	(4,360)	(216)	(1,245)
36	**Total Additions**			624,853	219,183	402,554	21,006	381,547	278,537	70,918	30,902	1,191	3,116
37	**Total Rate Base**			8,986,901	3,688,157	5,202,051	318,003	4,884,049	3,625,663	892,167	349,511	16,707	96,692
38	**Common Rate Base (@ 52.50%)**			4,718,122.9	1,936,283	2,731,077	166,951	2,564,126	1,903,473	468,388	183,493	8,771	50,763

2020 Class Cost of Service Study Detail ($000) — Page 7 of 14

	Operating Rev (Cal Month)			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Retail Revenue	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Present Rate Revenue	R01; (calc)	440, 442,444,445	3,120,405	1,165,785	1,927,911	109,370	1,818,541	1,364,535	311,884	135,923	6,199	26,709
2	Proposed Rate Revenue	PROREV; (calc)		3,320,983	1,253,775	2,037,525	117,863	1,919,662	1,439,792	331,010	142,431	6,429	29,683
3	Equal Rate Revenue			3,320,983	1,260,019	2,030,865	116,903	1,913,962	1,409,764	351,770	146,266	6,162	30,098
	Other Retail Revenue												
4	Interdepartmental	R01; R02	448	735	275	454	26	428	321	73	32	1	6
5	Gross Earnings Tax	R01; R02	408	0	0	0	0	0	0	0	0	0	0
6	CIP Adjustment to Program Costs	E99XCIP	456	0	0	0	0	0	0	0	0	0	0
7	**Tot Other Retail Rev**			735	275	454	26	428	321	73	32	1	6
	Other Operating Revenue												
8	Interchg Prod Capacity	P10	456	406,464	129,375	276,007	13,059	262,947	190,794	48,977	22,330	846	1,082
9	Interchg Prod Energy	E8760	456	0	0	0	0	0	0	0	0	0	0
10	Interchg Tr Bulk Supply	D10S	456	(8,285)	(3,194)	(5,091)	(282)	(4,809)	(3,604)	(862)	(327)	(16)	0
11	Dist Int Sales; Oth Serv	E8760	412,451,456	630	188	439	20	419	302	79	37	1	2
12	Dist Overhd Line Rent	POL	454	4,982	3,165	1,565	219	1,346	1,103	243	0	0	252
13	Connection Charges	C11	451	1,930	1,692	197	127	71	70	1	0	0	40
14	Sales For Resale	E8760	447	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
15	Joint Op Agree-Other PSCo Rev	D10S	456	0	0	0	0	0	0	0	0	0	0
16	Misc Ancillary Trans Rev	D10S		202,231	77,956	124,275	6,891	117,385	87,966	21,050	7,979	390	0
17	MISO	D10S	456	(83,828)	(32,314)	(51,514)	(2,856)	(48,658)	(36,463)	(8,726)	(3,307)	(162)	0
18	Other	D10S	451,456,457	15,207	5,862	9,345	518	8,827	6,615	1,583	600	29	0
19	Late Pay Chg - Pres	R16C; R02		5,687	4,895	787	321	466	441	24	1	1	5
20	**Tot Other Op - Pres**		450	545,018	187,626	356,011	18,017	337,994	247,223	62,368	27,313	1,090	1,381
21	Incr Misc Serv - Prop	R01,		447	167	276	16	261	196	45	19	1	4
22	Incr Inter-Dept'l - Prop	R01; R02		36	14	22	1	21	16	4	2	0	0
23	Incr Late Pay - Prop	(R16C); R02		366	315	51	21	30	28	2	0	0	0
	Tot Incr Other Op			849	495	349	38	312	240	50	21	1	4
24	**Tot Other Op - Prop**			545,867	188,121	356,360	18,054	338,306	247,463	62,418	27,334	1,091	1,386
25	**Tot Oper Rev - Pres**			3,666,158	1,353,685	2,284,375	127,412	2,156,964	1,612,079	374,326	163,268	7,290	28,097
26	**Tot Oper Rev - Prop**			3,867,585	1,442,171	2,394,339	135,943	2,258,396	1,687,576	393,502	169,797	7,521	31,075
	Tot Oper Rev - Eql			3,867,585	1,448,415	2,387,679	134,983	2,252,696	1,657,548	414,262	173,632	7,254	31,491
	Operating & Maint (Pg 1 of 2)												
	Production Expen												
27	**Fuel**	E8760	501,518,547	648,892	194,202	452,474	20,491	431,983	310,910	81,202	38,492	1,378	2,217
	Purchased Power												
28	Purchases: Cap Peak	D10S		95,319	36,743	58,576	3,248	55,328	41,462	9,922	3,761	184	0
29	Purchases: Cap Base	D10S		35,470	13,673	21,797	1,209	20,589	15,429	3,692	1,399	68	0
30	Purchases: Demand		555	130,789	50,416	80,373	4,456	75,916	56,890	13,614	5,160	252	0
31	Purchases: Other Energy	E8760	555	288,737	86,414	201,337	9,118	192,219	138,345	36,132	17,128	613	986
32	Tot Non-Assoc Purch			419,526	136,830	281,709	13,574	268,135	195,235	49,746	22,288	865	986
33	Interchg Agr Capacity	P10WoN	557	32,191	10,418	21,694	1,039	20,655	15,023	3,837	1,729	67	79
34	Interchg Agr Energy	E8760	557	16,285	4,874	11,355	514	10,841	7,803	2,038	966	35	56
35	Tot Wis Interchg Purch			48,476	15,291	33,050	1,553	31,496	22,825	5,875	2,695	101	135
36	**Tot Purchased Power**			468,001	152,121	314,759	15,128	299,631	218,061	55,621	24,983	967	1,121
	Other Production		500,502,505-507 509-514,517-519,520,										
37	Capacity Related	D10S	523-525,528-532,535,	94,530	36,439	58,090	3,221	54,870	41,118	9,840	3,730	182	0
38	Energy Related	E8760	539,543-546,548-550	341,503	102,206	238,130	10,784	227,346	163,627	42,735	20,258	725	1,167
39	Total Other Produc	21.68%	552-554,556,557 575.1-575.8	436,032.144	138,645	296,221	14,005	282,216	204,746	52,575	23,988	908	1,167
40	**Total Production**			1,552,926	484,968	1,063,454	49,624	1,013,830	733,717	189,398	87,463	3,253	4,504
41	**Transmission Exp**	D10S	560-563, 565-568 570-573	245,050	94,461	150,588	8,349	142,239	106,591	25,507	9,668	472	0

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

Northern States Power Company

2020 Class Cost of Service Study Detail ($000)

Operating & Maint (Pg 2 of 2)

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Distribution Expen	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Supervision & Eng'rg	ZDTS	580,590	6,898	3,972	2,623	318	2,306	1,847	401	55	2	303
2	Load Dispatching	T20D80	581	7,267	2,981	4,255	283	3,972	3,184	728	58	3	32
3	Substations	P61	582,591,592	9,044	3,669	5,327	354	4,973	3,878	959	133	3	48
4	Overhead Lines	POL	583,593	41,409	26,308	13,009	1,821	11,187	9,169	2,018	0	0	2,093
5	Underground Lines	PUL	584, 594	15,647	11,542	4,051	740	3,311	2,712	599	0	0	54
6	Line Transformers	P68	595	1,377	972	400	74	326	309	17	0	0	5
7	Meters	C12WM	586,597,598	1,997	1,324	668	198	470	441	27	1	0	4
8	Customer Install'n	OXDTS	587	3,750	2,227	1,310	165	1,145	930	205	9	0	213
9	Street Lighting	Dir Assign	585,596	2,273	0	0	0	0	0	0	0	0	2,273
10	Miscellaneous	OXDTS	588	21,261	12,629	7,425	934	6,491	5,275	1,165	49	2	1,207
11	Rents (Pole Attachmts)	POL	589	3,326	2,113	1,045	146	898	736	162	0	0	168
12	**Total Distribution**			114,249	67,735	40,113	5,033	35,081	28,484	6,282	305	10	6,400
13	**Customer Accounting**	C11WA	901-905	48,973	40,628	8,153	4,570	3,583	3,529	52	2	1	192
14	**Sales, Econ Dvlp & Other**	R01	912	(6)	(2)	(3)	(0)	(3)	(2)	(1)	(0)	(0)	(0)
	Admin & General												
15	Salaries	LABOR	920	72,889	28,672	43,485	2,710	40,774	30,100	7,470	3,083	121	732
16	Office Supplies	OXTS	921	48,424	17,123	31,008	1,676	29,332	21,486	5,416	2,338	92	294
17	Admin Transfer Credit	OXTS	922	(41,457)	(14,659)	(26,546)	(1,435)	(25,112)	(18,395)	(4,637)	(2,001)	(79)	(251)
18	Outside Services	LABOR	923	23,767	9,349	14,179	884	13,295	9,815	2,436	1,005	40	239
19	Property Insurance	NEPIS	924	5,732	2,375	3,293	204	3,089	2,297	563	218	11	63
20	Pensions & Benefits	LABOR	926	77,314	30,413	46,124	2,875	43,249	31,927	7,923	3,270	129	777
21	Injuries & Claims	LABOR	925	11,891	4,677	7,094	442	6,652	4,910	1,219	503	20	119
22	Regulatory Exp	R01; R02	928	5,151	1,924	3,182	181	3,002	2,252	515	224	10	44
23	General Advertising	OXTS	930.1	233	82	149	8	141	103	26	11	0	1
24	Contributions	OXTS		0	0	0	0	0	0	0	0	0	0
25	Misc General Exp	OXTS	929, 930.2	(322)	(114)	(206)	(11)	(195)	(143)	(36)	(16)	(1)	(2)
26	Rents	OXTS	931	42,587	15,059	27,270	1,474	25,797	18,897	4,763	2,056	81	258
27	Maint of General Plant	OXTS	935	757	268	485	26	459	336	85	37	1	5
28	Total			246,966	95,170	149,517	9,034	140,483	103,586	25,743	10,729	426	2,279
	Cust Service & Info												
29	Cust Assist Exp - Non-CIP	C11P10	908	2,277	1,360	889	111	778	575	138	63	2	27
30	CIP Total	E99XCIP	908	102,371.401	31,618	70,295	3,192	67,103	51,226	11,952	3,682	242	459
31	Instructional Advertising	C11P10	909	872	521	341	43	298	221	53	24	1	10
32	Total			105,520	33,500	71,525	3,346	68,179	52,022	12,143	3,768	245	496
33	Amortizations	LABOR		43,948	17,288	26,219	1,634	24,585	18,149	4,504	1,859	73	442
34	**Total O&M Expense**			2,357,626	833,748	1,509,566	81,590	1,427,977	1,046,075	263,627	113,794	4,481	14,312

2020 Class Cost of Service Study Detail ($000) Page 9 of 14

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

Book Depreciation

		Alloc	FERC Accounts	1=2+3+10 MN	2 Res	3=4+5 C&I Tot	4 Sm Non-D	5=6 to 9 Demand	6 Second	7 Primary	8 Tr Transf	9 Trans	10 St Ltg
	Production												
1	Peaking Plant	D10S		99,194	38,237	60,957	3,380	57,577	43,147	10,325	3,914	191	0
2	Base Load	E8760		290,224	86,859	202,374	9,165	193,209	139,058	36,318	17,216	616	991
3	Total		403,413	389,418	125,096	263,331	12,545	250,786	182,205	46,643	21,130	808	991
	Transmission												
4	Gen Step Up Base	E8760		1,239	371	864	39	825	594	155	74	3	4
5	Gen Step Up Peak	D10S		729	281	448	25	423	317	76	29	1	0
6	Total Gen Step Up			1,968	652	1,312	64	1,248	911	231	102	4	4
7	Bulk Transmission	D10S		66,350	25,577	40,774	2,261	38,513	28,861	6,906	2,618	128	0
8	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
9	Direct Assign	Dir Assign		120	0	120	0	120	20	0	0	100	0
10	Total		403,413	68,438	26,228	42,206	2,325	39,881	29,792	7,137	2,720	232	4
	Distribution												
11	Generat Step Up	STRATH		68	21	47	2	45	32	8	4	0	0
12	Bulk Transmission	D10S		37	14	23	1	22	16	4	1	0	0
13	Distrib Function	D60Sub		14,817	6,168	8,568	595	7,973	6,502	1,470	1	0	81
14	Direct Assign	Dir Assign		360	0	360	0	360	8	136	212	4	0
15	Total Substations		403,413	15,284	6,204	8,999	599	8,400	6,559	1,618	218	5	81
16	Overhead Lines	POL		31,887	20,258	10,017	1,402	8,615	7,061	1,554	0	0	1,612
17	Underground	PUL		36,367	26,826	9,416	1,720	7,696	6,304	1,392	0	0	126
18	Line Transformers	P68		11,127	7,856	3,231	594	2,637	2,499	139	0	0	40
19	Services	P69		10,216	9,225	991	308	682	682	0	0	0	0
20	Meters	C12WM		3,963	2,628	1,327	394	933	876	55	1	1	9
21	Street Lighting	P73		4,015	0	0	0	0	0	0	0	0	4,015
22	Total		403,413	112,860	72,998	33,980	5,017	28,963	23,981	4,757	220	6	5,881
23	**General & Common Plant**	PTD	403,413	112,676	45,079	66,609	3,959	62,650	46,343	11,463	4,632	213	987
24	**Total Book Deprec**		403,404	683,392	269,402	406,126	23,845	382,280	282,320	70,001	28,701	1,258	7,865

Real Estate & Property Tax

		Alloc	FERC Accounts	1=2+3+10 MN	2 Res	3=4+5 C&I Tot	4 Sm Non-D	5=6 to 9 Demand	6 Second	7 Primary	8 Tr Transf	9 Trans	10 St Ltg
	Production												
25	Peaking Plant	D10S		25,330	9,764	15,566	863	14,703	11,018	2,637	999	49	0
26	Base Load	E8760		64,379	19,268	44,892	2,033	42,859	30,847	8,056	3,819	137	220
27	Total		408.1	89,709	29,032	60,458	2,896	57,562	41,865	10,693	4,818	186	220
	Transmission												
28	Gen Step Up Base	E8760		909.4034	272	634	29	605	436	114	54	2	3
29	Gen Step Up Peak	D10S		384.0443	148	236	13	223	167	40	15	1	0
30	Total Gen Step Up			1,293.4477	420	870	42	828	603	154	69	3	3
31	Bulk Transmission	D10S		38,352.5481	14,784	23,568	1,307	22,262	16,682	3,992	1,513	74	0
32	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
33	Direct Assign	Dir Assign		70	0	70	0	70	12	0	0	58	0
34	Total		408.1	39,716.004	15,204	24,509	1,349	23,160	17,297	4,146	1,582	135	3
	Distribution												
35	Generat Step Up	STRATH		38	12	26	1	25	18	5	2	0	0
36	Bulk Transmission	D10S		21	8	13	1	12	9	2	1	0	0
37	Distrib Function	D60Sub		8,303	3,456	4,802	334	4,468	3,644	824	1	0	45
38	Direct Assign	Dir Assign		208	0	208	0	208	5	78	122	3	0
39	Total Substations			8,570	3,477	5,049	335	4,713	3,675	909	126	3	45
40	Overhead Lines	POL		11,372	7,225	3,573	500	3,072	2,518	554	0	0	575
41	Underground	PUL		18,252	13,463	4,726	863	3,862	3,164	698	0	0	63
42	Line Transformers	P68		5,118	3,614	1,486	273	1,213	1,149	64	0	0	18
43	Services	P69		3,583	3,235	347	108	239	239	0	0	0	0
44	Meters	C12WM		1,100	729	368	109	259	243	15	0	0	2
45	Street Lighting	P73		937	0	0	0	0	0	0	0	0	937
46	Total		408.1	48,932	31,743	15,548	2,189	13,359	10,989	2,241	126	3	1,641
47	**General & Common Plant**	PTD	408.1	0	0	0	0	0	0	0	0	0	0
48	**Tot Rl Est & Pr Tax**			178,357	75,979	100,515	6,434	94,081	70,151	17,079	6,527	323	1,864
49	Gross Earnings Tax	R01; R02		0	0	0	0	0	0	0	0	0	0
50	Payroll Taxes	LABOR		27,259	10,723	16,262	1,014	15,248	11,257	2,794	1,153	45	274
51	**Tot Non-Inc Taxes**			205,616	86,701	116,777	7,448	109,329	81,407	19,873	7,680	369	2,138

Northern States Power Company

2020 Class Cost of Service Study Detail ($000)

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Provision For Defer Inc Tax												
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		(3,008)	(1,160)	(1,849)	(103)	(1,746)	(1,309)	(313)	(119)	(6)	0
2	Nuclear Fuel	E8760		(6,621)	(1,982)	(4,617)	(209)	(4,408)	(3,173)	(829)	(393)	(14)	(23)
3	Base Load	E8760		28,632	8,569	19,965	904	19,061	13,719	3,583	1,698	61	98
4	Total		410, 411	19,002	5,428	13,499	593	12,907	9,238	2,441	1,187	41	75
	Transmission												
5	Gen Step Up Base	E8760		394	118	274	12	262	189	49	23	1	1
6	Gen Step Up Peak	D10S		140	54	86	5	81	61	15	6	0	0
7	Total Gen Step Up			533	172	360	17	343	249	64	29	1	1
8	Bulk Transmission	D10S		10,321	3,978	6,342	352	5,991	4,489	1,074	407	20	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		13	0	13	0	13	2	0	0	11	0
11	Total		410, 411	10,867	4,150	6,716	369	6,347	4,741	1,138	436	32	1
	Distribution												
12	Generat Step Up	STRATH		(27)	(9)	(19)	(1)	(18)	(13)	(3)	(2)	(0)	(0)
13	Bulk Transmission	D10S		(8)	(3)	(5)	(0)	(4)	(3)	(1)	(0)	(0)	0
14	Distrib Function	D60Sub		(1,537)	(640)	(889)	(62)	(827)	(674)	(152)	(0)	0	(8)
15	Direct Assign	Dir Assign		(69)	0	(69)	0	(69)	(2)	(26)	(40)	(1)	0
16	Total Substations			(1,641)	(651)	(981)	(63)	(918)	(692)	(182)	(42)	(1)	(8)
17	Overhead Lines	POL		645	410	203	28	174	143	31	0	0	33
18	Underground	PUL		(3,956)	(2,918)	(1,024)	(187)	(837)	(686)	(151)	0	0	(14)
19	Line Transformers	P68		(2,305)	(1,627)	(669)	(123)	(546)	(517)	(29)	0	0	(8)
20	Services	P69		(1,423)	(1,285)	(138)	(43)	(95)	(95)	0	0	0	0
21	Meters	C12WM		(279)	(185)	(93)	(28)	(66)	(62)	(4)	(0)	(0)	(1)
22	Street Lighting	P73		(319)	0	0	0	0	0	0	0	0	(319)
23	Total		410, 411	(9,277)	(6,256)	(2,703)	(415)	(2,288)	(1,909)	(335)	(42)	(1)	(318)
24	**General & Common Plant**	PTD	410, 411	(2,815)	(1,126)	(1,664)	(99)	(1,565)	(1,158)	(286)	(116)	(5)	(25)
25	**Net Operating Loss (NOL) Carry**	NEPIS		(93,712)	(38,837)	(53,842)	(3,333)	(50,509)	(37,558)	(9,209)	(3,567)	(176)	(1,032)
26	**Non - Plant Related**	LABOR	410, 411	5,719	2,250	3,412	213	3,199	2,362	586	242	10	57
27	**Tot Prov For Defer**			(70,215)	(34,392)	(34,582)	(2,673)	(31,909)	(24,285)	(5,665)	(1,860)	(99)	(1,241)
	Inv Tax Credit; Total Oper Exp												
	Production												
28	Peaking Plant	D10S		(260)	(100)	(160)	(9)	(151)	(113)	(27)	(10)	(1)	0
29	Base Load	E8760		(538)	(161)	(375)	(17)	(358)	(258)	(67)	(32)	(1)	(2)
30	Total		411	(798)	(261)	(535)	(26)	(509)	(371)	(94)	(42)	(2)	(2)
	Transmission												
31	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
32	Gen Step Up Peak	D10S		0	0	0	0	0	0	0	0	0	0
33	Total Gen Step Up			0	0	0	0	0	0	0	0	0	0
34	Bulk Transmission	D10S		(150)	(58)	(92)	(5)	(87)	(65)	(16)	(6)	(0)	0
35	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
36	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
37	Total		411	(150)	(58)	(92)	(5)	(87)	(65)	(16)	(6)	(0)	0
	Distribution												
38	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
39	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
40	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
41	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
42	Total Substations			0	0	0	0	0	0	0	0	0	0
43	Overhead Lines	POL		(268)	(170)	(84)	(12)	(72)	(59)	(13)	0	0	(14)
44	Underground	PUL		0	0	0	0	0	0	0	0	0	0
45	Line Transformers	P68		0	0	0	0	0	0	0	0	0	0
46	Services	P69		0	0	0	0	0	0	0	0	0	0
47	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
48	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
49	Total		411	(268)	(170)	(84)	(12)	(72)	(59)	(13)	0	0	(14)
50	**General & Common Plant**	PTD	411	(7)	(3)	(4)	(0)	(4)	(3)	(1)	(0)	(0)	(0)
51	**Net Inv Tax Credit**			(1,223)	(492)	(715)	(43)	(672)	(498)	(124)	(48)	(2)	(15)
52	**Total Operating Exp**			**3,175,196**	**1,154,966**	**1,997,171**	**110,166**	**1,887,005**	**1,385,018**	**347,712**	**148,267**	**6,007**	**23,059**
53A	**Pres Op Inc Before Inc Tax**			**490,962**	**198,719**	**287,204**	**17,245**	**269,959**	**227,061**	**26,614**	**15,001**	**1,284**	**5,038**
53B	**Prop Op Inc Before Inc Tax**			**692,389**	**287,204**	**397,168**	**25,777**	**371,391**	**302,557**	**45,789**	**21,530**	**1,515**	**8,016**

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PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

Tax Deprec; Inc Tax & Return

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		113,759	43,852	69,908	3,876	66,031	49,483	11,841	4,488	219	0
2	Nuclear Fuel	E8760		88,005	26,338	61,366	2,779	58,587	42,167	11,013	5,220	187	301
3	Base Load	E8760		476,283	142,543	332,113	15,040	317,073	228,206	59,602	28,253	1,012	1,627
4	Total		tax books	678,047	212,733	463,386	21,695	441,691	319,855	82,456	37,962	1,418	1,928
	Transmission												
5	Gen Step Up Base	E8760		3,093	926	2,157	98	2,059	1,482	387	183	7	11
6	Gen Step Up Peak	D10S		1,210	466	743	41	702	526	126	48	2	0
7	Total Gen Step Up			4,303	1,392	2,900	139	2,761	2,008	513	231	9	11
8	Bulk Transmission	D10S		112,468	43,354	69,114	3,832	65,282	48,921	11,707	4,437	217	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		182	0	182	0	182	30	0	0	151	0
11	Total		tax books	116,952	44,746	72,196	3,971	68,225	50,960	12,220	4,669	377	11
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		14	6	9	0	8	6	1	1	0	0
14	Distrib Function	D60Sub		11,679	4,862	6,754	469	6,284	5,125	1,159	1	0	64
15	Direct Assign	Dir Assign		186	0	186	0	186	4	70	109	2	0
16	Total Substations			11,879	4,867	6,948	470	6,478	5,135	1,230	111	2	64
17	Overhead Lines	POL		33,882	21,526	10,644	1,490	9,154	7,502	1,651	0	0	1,712
18	Underground	PUL		32,580	24,032	8,435	1,541	6,895	5,648	1,247	0	0	113
19	Line Transformers	P68		8,952	6,321	2,600	478	2,122	2,010	112	0	0	32
20	Services	P69		6,088	5,497	590	184	407	407	0	0	0	0
21	Meters	C12WM		2,823	1,872	945	280	664	624	39	1	1	6
22	Street Lighting	P73		3,372	0	0	0	0	0	0	0	0	3,372
23	Total		tax books	99,577	64,115	30,162	4,443	25,720	21,326	4,279	112	3	5,299
24	**General & Common Plant**	PTD	tax books	131,166	52,477	77,540	4,609	72,931	53,948	13,344	5,392	248	1,150
25	Net Operating Loss (NOL) Carry F	NEPIS		0	0	0	0	0	0	0	0	0	0
26	**Total Tax Deprec**			1,025,742	374,071	643,284	34,718	608,566	446,089	112,298	48,134	2,045	8,387
27	Interest Expense		427,431	187,826.23	77,082	108,723	6,646	102,077	75,776	18,646	7,305	349	2,021
28	Other Tax Timing Differ	LABOR		11,855	4,663	7,072	441	6,632	4,895	1,215	501	20	119
29	Meals & Enter	LABOR		584	230	348	22	326	241	60	25	1	6
30	Total Tax Deductions			1,226,007	456,047	759,428	41,827	717,601	527,002	132,219	55,965	2,415	10,533
	Inc Tax Additions												
31	Book Depreciation			683,392	269,402	406,126	23,845	382,280	282,320	70,001	28,701	1,258	7,865
32	Deferred Inc Tax & ITC			(71,438.19)	(34,884)	(35,298)	(2,716)	(32,581)	(24,783)	(5,789)	(1,908)	(101)	(1,256)
33	Nuclear Fuel Book Burn	E8760		105,136	31,465	73,311	3,320	69,991	50,375	13,157	6,237	223	359
34	Tax Capitalized Leases	PTD		43,158	17,266	25,513	1,516	23,996	17,750	4,391	1,774	81	378
35	Avoided Tax Interest	RTBASE		16,356	6,712	9,468	579	8,889	6,599	1,624	636	30	176
36	Total Tax Additions			776,603	289,962	479,119	26,544	452,575	332,260	83,383	35,440	1,492	7,522
37	**Total Inc Tax Adjustments**			(449,404)	(166,085)	(280,308)	(15,282)	(265,026)	(194,742)	(48,836)	(20,525)	(923)	(3,011)
38A	**Pres Taxable Net Income**			41,558	32,634	6,896	1,963	4,933	32,319	(22,222)	(5,524)	360	2,027
38B	**Prop Taxable Net Income**			242,985	121,119	116,860	10,494	106,365	107,816	(3,047)	1,005	591	5,006
39A	Pres Fed & State Inc Tax			(6,184)	1,940	(8,511)	(77)	(8,434)	1,975	(8,187)	(2,293)	70	388
39B	Prop Fed & State Inc Tax			51,710	27,372	23,094	2,375	20,720	23,675	(2,675)	(416)	136	1,244
40A	Pres Preliminary Return	(total); BASE		497,145	196,779	295,716	17,323	278,393	225,085	34,800	17,294	1,214	4,651
40B	Prop Preliminary Return	(total); BASE		640,678	259,832	374,073	23,402	350,672	278,883	48,465	21,946	1,378	6,773
41	Total AFUDC			28,846	10,486	18,225	973	17,252	12,627	3,209	1,360	57	135
42A	**Present Total Return**			525,991	207,265	313,941	18,296	295,645	237,712	38,009	18,653	1,271	4,785
42B	**Proposed Total Return**			669,524	270,318	392,298	24,375	367,923	291,509	51,673	23,306	1,435	6,908
43A	**Pres % Return on Rate Base**			5.85%	5.62%	6.03%	5.75%	6.05%	6.56%	4.26%	5.34%	7.61%	4.95%
43B	**Prop % Return on Rate Base**			7.45%	7.33%	7.54%	7.67%	7.53%	8.04%	5.79%	6.67%	8.59%	7.14%
44A	**Present Common Return**			338,165	130,183	205,218	11,650	193,568	161,935	19,363	11,348	922	2,765
44B	**Proposed Common Return**			481,698	193,236	283,575	17,729	265,847	215,733	33,027	16,001	1,086	4,887
45A	**Pres % Ret on Common Rt Base**			7.17%	6.72%	7.51%	6.98%	7.55%	8.51%	4.13%	6.18%	10.51%	5.45%
45B	**Prop % Ret on Common Rt Base**			10.21%	9.98%	10.38%	10.62%	10.37%	11.33%	7.05%	8.72%	12.38%	9.63%

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Allow For Funds Used During Constr

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		1,742	672	1,071	59	1,011	758	181	69	3	0
2	Nuclear Fuel	E8760		7,990	2,391	5,572	252	5,319	3,828	1,000	474	17	27
3	Base Load	E8760		7,966	2,384	5,555	252	5,303	3,817	997	473	17	27
4	Total		419.1,432	17,698	5,447	12,197	563	11,634	8,403	2,178	1,015	37	55
	Transmission												
5	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10S		356	137	219	12	207	155	37	14	1	0
7	Total Gen Step Up			356	137	219	12	207	155	37	14	1	0
8	Bulk Transmission	D10S		2,862	1,103	1,759	98	1,661	1,245	298	113	6	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		5	0	5	0	5	1	0	0	4	0
11	Total		419.1,432	3,224	1,241	1,983	110	1,874	1,401	335	127	11	0
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub		1,677	698	970	67	903	736	166	0	0	9
15	Direct Assign	Dir Assign		70	0	70	0	70	2	27	41	1	0
16	Total Substations			1,748	698	1,040	67	973	738	193	42	1	9
17	Overhead Lines	POL		598	380	188	26	161	132	29	0	0	30
18	Underground	PUL		1,007	743	261	48	213	175	39	0	0	3
19	Line Transformers	P68		0	0	0	0	0	0	0	0	0	0
20	Services	P69		296	267	29	9	20	20	0	0	0	0
21	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
23	Total		419.1,432	3,649	2,088	1,518	150	1,367	1,064	261	42	1	43
24	**General & Common Plant**	PTD	419.1,432	4,275	1,710	2,527	150	2,377	1,758	435	176	8	37
25	**Total AFUDC**			28,846	10,486	18,225	973	17,252	12,627	3,209	1,360	57	135

Labor Allocator

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
26	Other Prod - Cap	D10S		60,183	23,199	36,984	2,051	34,933	26,178	6,264	2,374	116	0
27	Other Prod - Ene	E8760		152,964	45,779	106,662	4,830	101,831	73,291	19,142	9,074	325	523
28	Total		500 through 557	213,147	68,979	143,646	6,881	136,765	99,469	25,406	11,448	441	523
	Transmission												
29	Stepup Subtrans	P5161A		676	219	455	22	433	315	80	36	1	2
30	Bulk Power Subs	D10S		20,037	7,724	12,313	683	11,631	8,716	2,086	791	39	0
31	Total		560 through 571	20,713	7,943	12,768	705	12,064	9,031	2,166	827	40	2
	Distribution												
32	Superv & Eng	ZDTS	580, 590	5,991	3,449	2,278	276	2,002	1,604	348	48	2	263
33	Load Dispatch	D10S	581	6,658	2,567	4,092	227	3,865	2,896	693	263	13	0
34	Substation	P61	582, 592	5,901	2,394	3,476	231	3,245	2,531	626	87	2	31
35	Overhead Lines	POL	583, 593	10,679	6,784	3,355	470	2,885	2,365	520	0	0	540
36	Underground Lines	PUL	584, 594	9,996	7,373	2,588	473	2,115	1,733	383	0	0	35
37	Line Transformer	P68	595	1,162	820	337	62	275	261	14	0	0	4
38	Meter	C12WM	586, 597	3,465	2,298	1,160	344	816	766	48	1	1	7
39	Cust Installation	ZDTS	587	3,415	1,966	1,299	157	1,141	915	199	27	1	150
40	Street Lighting	P73	585, 596	997	0	0	0	0	0	0	0	0	997
41	Miscellaneous	OXDTS	588	7,404	4,398	2,586	325	2,260	1,837	406	17	1	420
42	Total			55,668	32,049	21,171	2,565	18,606	14,907	3,237	443	19	2,448
43	**Cust Accounting**	C11WA	901,902,903,904,905	10,731	8,903	1,787	1,001	785	773	11	0	0	42
44	**Sales Expense**	C11P10	912	0	0	0	0	0	0	0	0	0	0
45	**Admin & General**	LABOR	920,921,922,923,924,	151,374	59,546	90,308	5,629	84,679	62,511	15,513	6,403	252	1,521
46	**Service & Inform**	C11P10	908, 909	1,168	698	456	57	399	295	71	32	1	14
47	**Labor**			452,801	178,117	270,135	16,838	253,297	186,986	46,404	19,153	754	4,549

Northern States Power Company

2020 Class Cost of Service Study Detail ($000)

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	
INTERNAL ALLOCATORS		Intern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	50% Cus, 50% Prod Plt	C11P10	100.00%	59.76%	39.07%	4.89%	34.17%	25.28%	6.04%	2.75%	0.10%	1.18%
2	Peaking Plant Capacity	D10S	100.00%	38.55%	61.45%	3.41%	58.04%	43.50%	10.41%	3.95%	0.19%	0.00%
3	57% Dmd; 43% Energy: Sales & I	D57E43	100.00%	29.93%	69.73%	3.16%	66.57%	47.91%	12.51%	5.93%	0.21%	0.34%
4	40% Dmd; 60% Energy: CIP	D40E60	100.00%	29.93%	69.73%	3.16%	66.57%	47.91%	12.51%	5.93%	0.21%	0.34%
5	20%D10T; 80%D60Sub	T20D80	100.00%	41.01%	58.55%	3.89%	54.66%	43.81%	10.02%	0.80%	0.04%	0.44%
6	Labor w/o (or w/) A&G	LABOR	100.00%	39.34%	59.66%	3.72%	55.94%	41.30%	10.25%	4.23%	0.17%	1.00%
7	Net Plant In Service	NEPIS	100.00%	41.44%	57.46%	3.56%	53.90%	40.08%	9.83%	3.81%	0.19%	1.10%
8	Dis O&M w/o Sup & Misc	OXDTS	100.00%	59.40%	34.92%	4.39%	30.53%	24.81%	5.48%	0.23%	0.01%	5.68%
9	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	100.00%	35.36%	64.03%	3.46%	60.57%	44.37%	11.18%	4.83%	0.19%	0.61%
10	Production Plant	P10	100.00%	31.83%	67.90%	3.21%	64.69%	46.94%	12.05%	5.49%	0.21%	0.27%
11	Production Plant Wo Nuclear	P10WoN	100.00%	32.36%	67.39%	3.23%	64.16%	46.67%	11.92%	5.37%	0.21%	0.25%
12	Total P51 & P61A	P5161A	100.00%	32.46%	67.30%	3.23%	64.07%	46.62%	11.90%	5.35%	0.21%	0.24%
13	Distribution Plant	P60	100.00%	64.87%	31.78%	4.47%	27.30%	22.46%	4.58%	0.26%	0.01%	3.35%
14	Distr Substn Plant	P61	100.00%	40.56%	58.91%	3.91%	54.99%	42.89%	10.61%	1.47%	0.03%	0.53%
15	Line Transformer Plant	P68	100.00%	70.60%	29.04%	5.34%	23.70%	22.45%	1.25%	0.00%	0.00%	0.36%
16	Services Plant	P69	100.00%	90.30%	9.70%	3.02%	6.68%	6.68%	0.00%	0.00%	0.00%	0.00%
17	Dist Plt Overhead Lines	POL	100.00%	63.53%	31.41%	4.40%	27.02%	22.14%	4.87%	0.00%	0.00%	5.05%
18	Real Est & Property Tax	PT0	100.00%	42.60%	56.36%	3.61%	52.75%	39.33%	9.58%	3.66%	0.18%	1.05%
19	Produc, Trans & Distrib	PTD	100.00%	40.01%	59.12%	3.51%	55.60%	41.13%	10.17%	4.11%	0.19%	0.88%
20	Dist Plt Undground Lines	PUL	100.00%	73.76%	25.89%	4.73%	21.16%	17.33%	3.83%	0.00%	0.00%	0.35%
21	Rate Base (Non-Column)	RTBASE	100.00%	41.04%	57.88%	3.54%	54.35%	40.34%	9.93%	3.89%	0.19%	1.08%
22	Stratified Hydro Baseload	STRATH	100.00%	31.40%	68.32%	3.20%	65.12%	47.16%	12.15%	5.59%	0.21%	0.28%
23	Transmission & Distrib	TD	100.00%	52.72%	45.46%	3.98%	41.47%	32.10%	7.26%	1.96%	0.16%	1.82%
24	Labor Dis w/o Sup & Eng	ZDTS	100.00%	57.57%	38.03%	4.61%	33.42%	26.78%	5.81%	0.80%	0.03%	4.40%

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
INTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
25	Labor w/o A&G	LABOR(S)	301,427	118,572	179,827	11,209	168,618	124,476	30,891	12,750	502	3,028
26	Dis O&M w/o Sup, Cust Install & M	OXDTS	82,339	48,908	28,755	3,616	25,139	20,430	4,511	192	6	4,676
27	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	2,302,253	814,065	1,474,224	79,671	1,394,553	1,021,538	257,495	111,145	4,375	13,964
28	Total P51 & P61A	P5161A	109,496	35,539	73,692	3,538	70,154	51,045	13,026	5,857	226	264
29	Produc, Trans & Distrib	PTD	18,267,302	7,308,392	10,798,820	641,859	10,156,961	7,513,199	1,858,382	750,910	34,470	160,090
30	Transmission & Distrib	TD	7,151,860	3,770,404	3,250,960	284,735	2,966,225	2,295,625	519,013	140,248	11,340	130,495
31	Labor Dis w/o Sup & Eng, Cust In	ZDTS	46,262	26,634	17,594	2,132	15,462	12,388	2,690	368	16	2,035

2020 Class Cost of Service Study Detail ($000) Page 14 of 14

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
EXTERNAL ALLOCATORS		Extern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Customers - Ave Monthly	C11	100.00%	87.68%	10.23%	6.58%	3.65%	3.62%	0.04%	0.00%	0.00%	2.09%
2	Cust Acctg Wtg Factor	C11WA	100.00%	82.96%	16.65%	9.33%	7.32%	7.21%	0.11%	0.00%	0.00%	0.39%
3	Mo Cus Wtd By Mtr Invest	C12WM	100.00%	66.31%	33.47%	9.93%	23.54%	22.10%	1.38%	0.04%	0.02%	0.22%
4	Sec & Pri Customers	C61PS	100.00%	89.16%	10.42%	6.69%	3.73%	3.69%	0.04%	0.00%	0.00%	0.42%
5	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	100.00%	95.24%	4.52%	3.88%	0.64%	0.63%	0.01%	0.00%	0.00%	0.24%
6	C62Sec, w/o Ltg & C/I Undergrou	C62NL	100.00%	94.89%	5.11%	3.29%	1.82%	1.82%	0.00%	0.00%	0.00%	0.00%
7	Secondary Customers	C62Sec	100.00%	89.19%	10.38%	6.69%	3.69%	3.69%	0.00%	0.00%	0.00%	0.42%
8	Summer Peak Resp KW	D10S	100.00%	38.55%	61.45%	3.41%	58.04%	43.50%	10.41%	3.95%	0.19%	0.00%
9	Transmission Demand %	D10T	100.00%	35.79%	63.89%	3.35%	60.54%	44.91%	10.76%	4.68%	0.19%	0.32%
10	Winter Peak Resp KW	D10W	100.00%	31.90%	67.32%	3.26%	64.06%	46.91%	11.25%	5.73%	0.18%	0.77%
11	Alternative Production Allocator	1CP	100.00%	38.55%	61.45%	3.41%	58.04%	43.50%	10.41%	3.95%	0.19%	0.00%
12	Sec, Pri & TT, Class Coin kW @ S	D60Sub	100.00%	41.63%	57.83%	4.02%	53.81%	43.88%	9.92%	0.01%	0.00%	0.54%
13	Sec & Pri, Cl Coin kW (no Min Sys	D61PS	100.00%	36.61%	63.07%	3.36%	59.70%	48.21%	11.50%	0.00%	0.00%	0.33%
14	Pri & Sec Coin kW Served w/ 1 Pl	D61PS1Ph	100.00%	74.43%	25.21%	3.71%	21.50%	15.72%	5.78%	0.00%	0.00%	0.35%
15	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	100.00%	74.45%	25.55%	2.06%	23.49%	23.49%	0.00%	0.00%	0.00%	0.00%
16	Sec, Class Coin kW (w/o Min Sys	D62SecL	100.00%	49.35%	50.40%	3.62%	46.78%	46.78%	0.00%	0.00%	0.00%	0.26%
17	Direct Assign Street Lighting	DASL	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
18	On + Off Sales MWH	E8760	100.00%	29.93%	69.73%	3.16%	66.57%	47.91%	12.51%	5.93%	0.21%	0.34%
19	Street Lighting (Dir Assign)	P73	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
20	MWh Sales Excl CIP Exempt	E99XCIP	100.00%	30.89%	68.67%	3.12%	65.548%	50.04%	11.68%	3.60%	0.24%	0.45%
21	Present Rev	R01	100.00%	37.36%	61.78%	3.50%	58.28%	43.73%	9.99%	4.36%	0.20%	0.86%
22	Late Fee Revenue Allocator	LateFee	100.00%	86.07%	13.84%	5.65%	8.19%	7.75%	0.41%	0.01%	0.02%	0.09%

			6	**7**	**11**	**12**	**13**	**15**	**16**	**17**	**18**	**36**
			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
EXTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
23	Customers - B Basis	C10	1,308,442	1,166,597	136,327	87,551	48,776	48,273	479	15	9	5,518
24	Cust - Ave Monthly (C10-Area Lt)	C11	1,334,596	1,170,186	136,525	87,750	48,776	48,273	479	15	9	27,884
25	Mo Cus Wtd By Cus Acct	C11WA	1,410,543	1,170,186	234,839	131,625	103,214	101,636	1,487	58	33	5,518
26	Cust Acctg Wtg Factor	C11WAF	15.25	1.00	14.25	1.50	12.75	2.11	3.11	3.88	3.67	N/A
27	Cust-Ave Mo (C11 w/ Dir Assign S	C12	1,309,242	1,170,186	136,525	87,750	48,776	48,273	479	15	9	2,531
28	Mo Cus Wtd By Mtr Invest	C12WM	168,074,379	111,457,771	56,254,898	16,694,462	39,560,436	37,149,248	2,311,593	62,595	36,999	361,709
29	Meter Invest / Cust Factor	C12WMF	14,311	95	14,073	190	13,883	770	4,829	4,173	4,111	143
30	Sec & Pri Customers	C61PS	1,308,418	1,166,597	136,303	87,551	48,752	48,273	479	0	0	5,518
31	% Served by Primary Single Phase		0.0%	73.59%	0.00%	39.93%	0.00%	11.80%	18.18%	0.00%	0.00%	39.28%
32	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	901,370	858,455	40,747	34,962	5,785	5,698	87	0	0	2,167
33	C62Sec, w/o Ltg & C/I Undergrou	C62NL	1,229,438	1,166,597	62,841	40,507	22,334	22,334	0	0	0	0
34	Secondary Customers	C62Sec	1,307,939	1,166,597	135,824	87,551	48,273	48,273	0	0	0	5,518
35	Summer Peak Resp KW	D10S	25,965	10,009	15,956	885	15,071	11,294	2,703	1,024	50	0
36	Dmd (D10S x Fact + D10W)/1000	D10T	10,000,000	3,579,045	6,388,895	334,711	6,054,184	4,491,177	1,075,603	468,465	18,938	32,060
37	Winter Peak Resp KW	D10W	4,222	1,347	2,842	138	2,705	1,980	475	242	8	33
38	Alternative Production Allocator	1CP	25,965	10,009	15,956	885	15,071	11,294	2,703	1,024	50	0
39	Sec, Pri & TT, Class Coin kW @ S	D60Sub	6,631,290	2,760,494	3,834,708	266,370	3,568,338	2,909,950	657,806	582	0	36,088
40	Sec & Pri, Class Coin kW (w/o Mi	D61PS	5,962,429	2,182,570	3,760,440	200,622	3,559,818	2,874,362	685,456	0	0	19,419
41	Pri & Sec Coin kW Served w/ 1 Pl	D61PS1Ph	2,157,736	1,606,071	544,037	80,116	463,921	339,293	124,628	0	0	7,628
42	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	10,485,113	7,806,290	2,678,823	216,305	2,462,517	2,462,517	0	0	0	0
43	Sec, Class Coin kW (w/o Min Sys	D62SecL	10,000,000	4,934,673	5,039,796	361,776	4,678,020	4,678,020	0	0	0	25,531
44	Annual Billing kW	D99	50,585.647	0	50,586	0	50,586	38,601	8,077	3,687	220	0
45	Summer Billing kW	D99S	18,568.179	0	18,568	0	18,568	14,099	3,038	1,343	89	0
46	Winter Billing kW	D99W	32,017.467	0	32,017	0	32,017	24,502	5,039	2,344	132	0
47	Non-Coinc Pk Second	DN-Sec	13,615,653	7,806,290	5,789,944	467,517	5,322,426	5,322,426	0	0	0	19,419
48	MWh Sales	E99	28,838,347	8,450,856	20,264,816	853,252	19,411,564	13,765,907	3,724,793	1,856,137	64,727	122,675
49	MWh Sales Excl CIP Exempt	E99XCIP	27,361,954	8,450,856	18,788,423	853,090	17,935,333	13,691,871	3,194,646	984,089	64,727	122,675
50	Late Fee Revenue Allocation	LateFee	100.00%	86.07%	13.84%	5.65%	8.19%	7.75%	0.41%	0.01%	0.02%	0.09%

Northern States Power Company

2021 Class Cost of Service Study Detail ($000)

Rate Base

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Plant In Service	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Production		11,481,125	3,640,788	7,809,495	369,641	7,439,854	5,400,291	1,382,047	628,604	28,912	30,843
2	Transmission		3,359,259	1,281,836	2,077,128	114,282	1,962,846	1,466,151	350,613	133,460	12,622	296
3	Distribution		4,136,381	2,684,186	1,317,510	184,768	1,132,742	931,527	191,034	9,934	247	134,685
4	General		1,841,188	738,038	1,087,062	64,879	1,022,183	756,584	186,643	74,902	4,054	16,089
5	Common		0	0	0	0	0	0	0	0	0	0
6	Total Plant In Service		20,817,953	8,344,847	12,291,194	733,569	11,557,625	8,554,553	2,110,338	846,900	45,834	181,912
7	Production		6,774,974	2,141,031	4,615,448	217,910	4,397,538	3,190,484	817,335	372,632	17,087	18,495
8	Transmission		787,936	301,294	486,605	26,812	459,793	343,337	81,986	31,095	3,375	37
9	Distribution		1,519,172	1,008,064	474,046	69,424	404,622	335,565	65,240	3,716	101	37,062
10	General		922,457	369,766	544,631	32,505	512,126	379,058	93,510	37,527	2,031	8,061
11	Common		0	0	0	0	0	0	0	0	0	0
12	Total Depreciation Reserve		10,004,539	3,820,155	6,120,730	346,651	5,774,079	4,248,444	1,058,071	444,970	22,594	63,654
13	**Net Plant In Service**		10,813,415	4,524,692	6,170,464	386,918	5,783,546	4,306,109	1,052,267	401,930	23,240	118,258
14	Deducts: Accum Defer Inc Tax		2,187,638	894,128	1,271,284	78,102	1,193,182	887,867	216,780	83,553	4,983	22,226
15	Constr Work In Progress		417,804	163,884	251,587	14,607	236,981	175,066	43,555	17,501	858	2,332
16	Fuel Inventory		65,875	19,647	46,001	2,085	43,916	31,623	8,231	3,892	170	227
17	Materials & Supplies		153,932	52,292	100,975	5,082	95,892	69,934	17,740	7,843	374	665
18	Prepayments		92,118	38,545	52,565	3,296	49,269	36,683	8,964	3,424	198	1,007
19	Non-Plant & Work Cash		(45,960)	(22,532)	(22,916)	(1,585)	(21,331)	(16,266)	(3,797)	(1,165)	(103)	(512)
20	Total Additions		683,768	251,836	428,213	23,485	404,728	297,040	74,694	31,495	1,498	3,719
21	**Rate Base**		9,309,544	3,882,400	5,327,393	332,301	4,995,091	3,715,283	910,181	349,872	19,755	99,751

Income Statement

22A	**Tot Oper Rev - Pres**	3,641,182	1,339,706	2,273,352	126,831	2,146,521	1,604,333	371,710	161,875	8,603	28,125
22B	**Tot Oper Rev - Prop**	3,988,977	1,491,504	2,465,081	140,835	2,324,246	1,736,869	404,203	173,990	9,184	32,392
23	Oper & Maint	2,409,148	853,857	1,540,176	83,901	1,456,275	1,067,897	267,922	114,958	5,499	15,115
24	Book Depr + IRS Int	719,524	283,406	428,008	25,147	402,861	297,629	73,627	30,043	1,562	8,110
25	Payroll, Rl Est & Prop Tax	210,876	88,984	119,720	7,651	112,069	83,490	20,335	7,805	439	2,172
26	Deferred Inc Tax & Net ITC	(172,672)	(74,739)	(95,678)	(6,274)	(89,403)	(66,818)	(16,165)	(6,074)	(346)	(2,254)
27A	Present Income Tax	59,576	25,772	32,768	2,108	30,661	30,460	(893)	865	228	1,036
27B	Proposed Income Tax	159,540	69,402	87,875	6,133	81,742	68,554	8,446	4,347	396	2,263
28	Allow Funds Dur Const	31,000	12,055	18,796	1,075	17,721	13,105	3,253	1,296	67	148
29A	**Present Return**	445,729	174,481	267,154	15,373	251,780	204,780	30,138	15,574	1,289	4,094
29B	**Proposed Return**	693,561	282,650	403,777	25,352	378,424	299,223	53,291	24,207	1,703	7,135
30A	**Pres Ret on Rt Base**	4.79%	4.49%	5.01%	4.63%	5.04%	5.51%	3.31%	4.45%	6.52%	4.10%
30B	**Prop Ret on Rt Base**	**7.45%**	7.28%	7.58%	7.63%	7.58%	8.05%	5.86%	6.92%	8.62%	7.15%
31A	**Pres Ret on Common**	5.14%	4.58%	5.57%	4.83%	5.62%	6.52%	2.33%	4.50%	8.44%	3.84%
31B	**Prop Ret on Common**	**10.21%**	9.89%	10.46%	10.55%	10.45%	11.36%	7.17%	9.20%	12.44%	9.64%

Northern States Power Company

2021 Class Cost of Service Study Detail ($000)

PRES vs Equal Rev Reqts

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	**UnAdj Equal Rev Reqt @ 7.45%**		**3,426,848**	**1,308,331**	**2,087,171**	**121,389**	**1,965,782**	**1,449,685**	**360,199**	**148,393**	**7,505**	**31,346**
2	**Present Revenue**		**3,080,208**	**1,148,029**	**1,905,512**	**108,275**	**1,797,236**	**1,348,907**	**307,387**	**133,692**	**7,250**	**26,668**
3	**UnAdj Revenue Deficiency**		**346,640**	**160,302**	**181,660**	**13,113**	**168,546**	**100,778**	**52,811**	**14,701**	**256**	**4,678**
4	**UnAdj Deficiency / Present**		**11.25%**	**13.96%**	**9.53%**	**12.11%**	**9.38%**	**7.47%**	**17.18%**	**11.00%**	**3.53%**	**17.54%**
			[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS									
5	**Pres Int Rate Discounts**											
6	**Pres Econ Dvlp Rate Discounts**											
7	**Pres Int Rate Disc Cost Alloc**	**D10S**										
8	**Pres Econ Dvlp Disc Cost Alloc**	**R01**										
										HIGHLY CONFIDENTIAL TRADE SECRET ENDS]		
9	**Revenue Requirement Shift**		**0**	**(1,960)**	**1,956**	**1,424**	**532**	**9,840**	**(2,299)**	**(6,787)**	**(223)**	**4**
10	**Adj Equal Rev Reqt (Rows 1+9)**		**3,426,848**	**1,306,371**	**2,089,127**	**122,813**	**1,966,314**	**1,459,526**	**357,900**	**141,606**	**7,282**	**31,349**
11	**Adj Rev Defic vs Pres Rev (Row 2)**		**346,640**	**158,343**	**183,616**	**14,538**	**169,078**	**110,618**	**50,513**	**7,914**	**32**	**4,682**
12	**Adj Deficiency / Adj Present**		**11.25%**	**13.79%**	**9.64%**	**13.43%**	**9.41%**	**8.20%**	**16.43%**	**5.92%**	**0.45%**	**17.56%**
	Equal Customer Classification											
13	Min Sys & Service Drop		251,521	204,307	24,084	13,892	10,192	9,946	255	(12)	3	23,130
14	Energy Services		60,997	50,709	10,008	5,620	4,388	4,321	63	2	1	280
15	Total Customer **(Cusco)**		312,517	255,016	34,092	19,512	14,580	14,267	318	(10)	5	23,409
16	Ave Monthly Customers		1,345,380	1,180,196	137,160	88,160	49,001	48,497	479	15	9	28,024
17	Svc Drop Reqt	$ / Mo / Cust	$15.58	$14.43	$14.63	$13.13	$17.33	$17.09	$44.37	($68.10)	$29.39	$68.78
18	Ener Svcs Reqt	$ / Mo / Cust	$3.78	$3.58	$6.08	$5.31	$7.46	$7.42	$10.90	$13.56	$12.84	$0.83
19	Total Reqt	$ / Mo / Cust	$19.36	$18.01	$20.71	$18.44	$24.80	$24.52	$55.27	($54.54)	$42.22	$69.61
	Equal Energy Classification											
20	On Peak Rev Reqt		810,664	231,977	577,345	29,812	547,533	400,346	101,091	43,981	2,114	1,342
21	Off Peak Rev Reqt		815,151	252,470	558,312	21,523	536,788	383,436	101,491	49,735	2,128	4,370
22	Total Ener Rev Reqt		1,625,815	484,447	1,135,657	51,335	1,084,321	783,782	202,582	93,716	4,242	5,712
23	Annual MWh Sales		28,388,116.803	8,289,824	19,976,823	841,814	19,135,010	13,576,274	3,661,168	1,819,766	77,801	121,470
24	On Pk Reqt	Mills / kWh	28.556	27.983	28.901	35.414	28.614	29.489	27.612	24.169	27.173	11.047
25	Off Pk Reqt	Mills / kWh	28.715	30.455	27.948	25.568	28.053	28.243	27.721	27.330	27.349	35.975
26	Total Reqt	Mills / kWh	57.271	58.439	56.849	60.982	56.667	57.732	55.333	51.499	54.521	47.022
	Equal Demand Classification											
27	Energy-Related Prod		360,354	110,510	248,732	11,487	237,245	171,484	44,273	20,566	921	1,111
28	Capacity-Related Summer Peak Prod		303,199	116,299	186,900	10,341	176,559	132,339	31,593	11,935	692	0
29	Capacity-Related Winter Peak Prod		91,639	35,150	56,489	3,126	53,363	39,998	9,549	3,607	209	0
30	Total Capacity-Related Prod		394,839	151,449	243,389	13,467	229,922	172,337	41,141	15,542	901	0
31	Total Production		755,192	261,960	492,122	24,954	467,167	343,822	85,415	36,108	1,823	1,111
32	Transmission **(Transco)**		444,192	170,230	273,962	15,135	258,827	193,728	46,224	17,463	1,411	0
33	Primary Dist Subs		90,773	36,819	53,466	3,573	49,892	39,175	9,577	1,115	25	488
34	Prim Dist Lines		169,157	84,070	84,520	5,909	78,610	62,527	16,083	0	0	567
35	Second Dist. Trans		29,201	15,788	13,353	969	12,384	12,384	0	0	0	60
36	Total Distribution **(Disco)**		289,131	136,678	151,339	10,452	140,887	114,087	25,660	1,115	25	1,114
37	Total Demand Rev Reqt		1,488,515	568,868	917,423	50,541	866,881	651,637	157,299	54,687	3,259	2,225
38	Annual Billing kW		49,881,486	0	49,881,486	0	49,881,486	38,073,588	7,940,141	3,618,195	249,562	0
39	Base Rev Reqt	$ / kW	$0.00	$0.00	$4.99	$0.00	$4.76	$4.50	$5.58	$5.68	$3.69	$0.00
40	Summer Rev Reqt	$ / kW	$0.00	$0.00	$3.75	$0.00	$3.54	$3.48	$3.98	$3.30	$2.77	$0.00
41	Winter Rev Reqt	$ / kW	$0.00	$0.00	$1.13	$0.00	$1.07	$1.05	$1.20	$1.00	$0.84	$0.00
42	Prod Rev Reqt	$ / kW	$0.00	$0.00	$9.87	$0.00	$9.37	$9.03	$10.76	$9.98	$7.30	$0.00
43	Tran Rev Reqt	$ / kW	$0.00	$0.00	$5.49	$0.00	$5.19	$5.09	$5.82	$4.83	$5.65	$0.00
44	Dist Rev Reqt	$ / kW	$0.00	$0.00	$3.03	$0.00	$2.82	$3.00	$3.23	$0.31	$0.10	$0.00
45	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$18.39	$0.00	$17.38	$17.12	$19.81	$15.11	$13.06	$0.00
46	Tot Dmd Rev Reqt	Mills / kWh	52.434	68.622	45.924	60.039	45.303	47.998	42.964	30.052	41.889	18.315
47	Summer Billing kW		18,305,301	0	18,305,301	0	18,305,301	13,906,603	2,991,491	1,319,367	87,840	0
48	Winter Billing kW		31,576,184	0	31,576,184	0	31,576,184	24,166,985	4,948,650	2,298,828	161,722	0
49	Tot Summer Reqt	$ / kW	$0.00	$0.00	$23.72	$0.00	$22.41	$22.11	$25.19	$19.86	$17.33	$0.00
50	Tot Winter Reqt	$ / kW	$0.00	$0.00	$15.30	$0.00	$14.46	$14.24	$16.56	$12.39	$10.74	$0.00
51	Energy + Production **(Genco)**		2,381,008	746,407	1,627,778	76,290	1,551,489	1,127,604	287,996	129,824	6,064	6,823

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

Northern States Power Company Docket No. E002/GR-19-564

2021 Class Cost of Service Study Detail ($000)

PROP vs Equal Rev Reqts

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	**Proposed Ret On Rt Base**		**7.45%**	**7.28%**	**7.58%**	**7.63%**	**7.58%**	**8.05%**	**5.86%**	**6.92%**	**8.62%**	**7.15%**
2	**UnAdj Equalized Rev Reqt**		**3,426,848**	**1,308,331**	**2,087,171**	**121,389**	**1,965,782**	**1,449,685**	**360,199**	**148,393**	**7,505**	**31,346**
3	**Proposed Revenue**		**3,426,848**	**1,299,084**	**2,096,834**	**122,225**	**1,974,609**	**1,481,169**	**339,826**	**145,785**	**7,830**	**30,930**
4	**UnAdj Revenue Deficiency**		**(0)**	**9,247**	**(9,663)**	**(836)**	**(8,827)**	**(31,483)**	**20,372**	**2,608**	**(324)**	**416**
5	**UnAdj Deficiency / Proposed**		**0.00%**	**0.71%**	**-0.46%**	**-0.68%**	**-0.45%**	**-2.13%**	**5.99%**	**2%**	**-4%**	**1.35%**
			[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS									
6	**Prop Interrupt Rate Discounts**											
7	**Prop Econ Dev Rate Discounts**											
8	**Prop Int Rate Disc Cost Alloc**	**D10S**										
9	**Prop ED Discount Cost Alloc**	**R01**										
												HIGHLY CONFIDENTIAL TRADE SECRET ENDS]
10	**Revenue Requirement Shift**		**0**	**3,272**	**(3,276)**	**1,665**	**(4,942)**	**7,201**	**(4,168)**	**(7,702)**	**(273)**	**4**
11	**Adj Equal Rev (Rows 2+10)**		**3,426,848**	**1,311,603**	**2,083,895**	**123,054**	**1,960,841**	**1,456,887**	**356,031**	**140,691**	**7,232**	**31,350**
12	**Adj Rev Defic vs Prop Rev (Row 3)**		**(0)**	**12,519**	**(12,939)**	**829**	**(13,769)**	**(24,282)**	**16,205**	**(5,094)**	**(598)**	**421**
13	**Adj Deficiency / Adj Prop**		**0.00%**	**0.96%**	**-0.62%**	**0.68%**	**-0.70%**	**-1.64%**	**4.77%**	**-3.49%**	**-7.63%**	**1.36%**
	Prop Customer Component											
14	Min Sys & Service Drop		247,923	200,866	24,322	13,945	10,377	10,139	247	(12)	3	22,735
15	Energy Services		60,986	50,699	10,008	5,620	4,388	4,321	63	2	1	280
16	Total Customer **(Cusco)**		308,910	251,565	34,330	19,565	14,765	14,460	310	(10)	5	23,015
17	Ave Monthly Customers		1,345,380	1,180,196	137,160	88,160	49,001	48,497	479	15	9	28,024
18	Svc Drop Reqt	$ / Mo / Cust	$15.36	$14.18	$14.78	$13.18	$17.65	$17.42	$42.99	($68.35)	$29.70	$67.61
19	Ener Svcs Reqt	$ / Mo / Cust	$3.78	$3.58	$6.08	$5.31	$7.46	$7.43	$10.89	$13.55	$12.84	$0.83
20	Total Reqt	$ / Mo / Cust	$19.13	$17.76	$20.86	$18.49	$25.11	$24.85	$53.88	($54.80)	$42.54	$68.44
	Prop Energy Component											
21	On Peak Rev Reqt		810,461	231,888	577,232	29,809	547,423	400,427	100,932	43,949	2,115	1,341
22	Off Peak Rev Reqt		814,931	252,372	558,191	21,521	536,670	383,513	101,331	49,698	2,129	4,368
23	Total Ener Rev Reqt		1,625,392	484,260	1,135,423	51,330	1,084,093	783,939	202,263	93,646	4,245	5,710
24	Annual MWh Sales		28,388,117	8,289,824	19,976,823	841,814	19,135,010	13,576,274	3,661,168	1,819,766	77,801	121,470
25	On Pk Reqt	Mills / kWh	28.549	27.973	28.895	35.410	28.608	29.495	27.568	24.151	27.190	11.044
26	Off Pk Reqt	Mills / kWh	28.707	30.444	27.942	25.565	28.047	28.249	27.677	27.310	27.367	35.962
27	Total Reqt	Mills / kWh	57.256	58.416	56.837	60.975	56.655	57.743	55.246	51.461	54.557	47.006
	Prop Demand Component											
28	Energy-Related Prod		364,638	109,434	254,100	11,910	242,190	187,474	34,537	19,096	1,083	1,104
29	Capacity-Related Summer Peak Prod		302,690	115,358	187,332	10,394	176,939	135,053	29,522	11,643	722	0
30	Capacity-Related Winter Peak Prod		91,485	34,866	56,620	3,141	53,478	40,818	8,923	3,519	218	0
31	Total Capacity-Related Prod		394,175	150,224	243,952	13,535	230,417	175,871	38,444	15,161	940	0
32	Total Production		758,814	259,658	498,052	25,445	472,607	363,345	72,981	34,258	2,023	1,104
33	Transmission **(Transco)**		445,815	168,975	276,839	15,364	261,476	201,751	41,349	16,845	1,531	0
34	Primary Dist Subs		90,726	36,416	53,827	3,612	50,215	40,607	8,535	1,046	27	483
35	Prim Dist Lines		168,003	82,766	84,678	5,940	78,738	64,350	14,388	0	0	559
36	Second Dist. Trans		29,188	15,445	13,685	969	12,716	12,716	0	0	0	58
37	Total Distribution **(Disco)**		287,918	134,626	152,190	10,522	141,669	117,673	22,923	1,046	27	1,101
38	Total Demand Rev Reqt		1,492,546	563,260	927,082	51,331	875,751	682,769	137,253	52,148	3,581	2,205
39	Annual Billing kW		49,881,486	0	49,881,486	0	49,881,486	38,073,588	7,940,141	3,618,195	249,562	0
40	Base Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$4.86	$4.92	$4.35	$5.28	$4.34	$0.00
41	Summer Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$3.55	$3.55	$3.72	$3.22	$2.89	$0.00
42	Winter Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$1.07	$1.07	$1.12	$0.97	$0.87	$0.00
43	Prod Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$9.47	$9.54	$9.19	$9.47	$8.11	$0.00
44	Tran Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$5.24	$5.30	$5.21	$4.66	$6.13	$0.00
45	Dist Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$2.84	$3.09	$2.89	$0.29	$0.11	$0.00
46	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$17.56	$17.93	$17.29	$14.41	$14.35	$0.00
47	Tot Dmd Rev Reqt	Mills / kWh	52.576	67.946	46.408	60.976	45.767	50.291	37.489	28.657	46.022	18.153
48	Summer Billing kW		18,305,301	0	18,305,301	0	18,305,301	13,906,603	2,991,491	1,319,367	87,840	0
49	Winter Billing kW		31,576,184	0	31,576,184	0	31,576,184	24,166,985	4,948,650	2,298,828	161,722	0
50	Tot Summer Reqt	$ / kW	$0.00	$0.00	$23.93	$0.00	$22.60	$23.03	$22.31	$19.05	$18.80	$0.00
51	Tot Winter Reqt	$ / kW	$0.00	$0.00	$15.49	$0.00	$14.63	$15.00	$14.25	$11.75	$11.93	$0.00
52	Energy + Production **(Genco)**		2,384,206	743,917	1,633,475	76,775	1,556,700	1,147,284	275,244	127,904	6,268	6,814
53	Prop Rev - Pres Rev (Pg 2)		346,640	151,056	191,323	13,950	177,373	132,261	32,439	12,093	580	4,262
54	Difference / Present		11.25%	13.16%	10.04%	12.88%	9.87%	9.81%	10.55%	9.05%	8.00%	15.98%

Northern States Power Company

2021 Class Cost of Service Study Detail ($000)

Original Plant in Service

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Summer Peak	D10S		1,929,004	741,648	1,187,356	65,864	1,121,492	840,647	200,655	75,794	4,396	0
2	WInter Peak	D10S		583,024	224,156	358,868	19,907	338,961	254,078	60,646	22,908	1,329	0
3	Total Peak	D10S		2,512,028	965,804	1,546,224	85,771	1,460,453	1,094,725	261,302	98,702	5,724	0
4	Base Load	E8760		6,433,729	1,918,824	4,492,781	203,626	4,289,155	3,088,476	803,935	380,110	16,633	22,124
5	Nuclear Fuel	E8760		2,535,368	756,160	1,770,490	80,244	1,690,246	1,217,090	316,810	149,792	6,555	8,719
6	Total	28.08%	120, 310-346	11,481,125	3,640,788	7,809,495	369,641	7,439,854	5,400,291	1,382,047	628,604	28,912	30,843
	Transmission												
7	Gen Step Up Base	E8760		86,031	25,658	60,077	2,723	57,354	41,299	10,750	5,083	222	296
8	Gen Step Up Peak	D10S		35,990	13,837	22,153	1,229	20,924	15,684	3,744	1,414	82	0
9	Total Gen Step Up			122,022	39,496	82,230	3,952	78,278	56,983	14,494	6,497	304	296
10	Bulk Transmission	D10S		3,231,290	1,242,340	1,988,950	110,330	1,878,620	1,408,175	336,119	126,963	7,363	0
11	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign		5,947	0	5,947	0	5,947	993	0	0	4,954	0
13	Total		350-359	3,359,259	1,281,836	2,077,128	114,282	1,962,846	1,466,151	350,613	133,460	12,622	296
	Distribution:												
	Substations												
14	Generat Step Up	STRATH		3,046	953	2,084	98	1,986	1,439	370	170	8	9
15	Bulk Transmission	D10S		1,745	671	1,074	60	1,015	761	182	69	4	0
16	Distrib Function	D60Sub		694,361	288,632	401,920	27,980	373,940	305,642	68,855	(557)	0	3,808
17	Direct Assign	Dir Assign		17,385,902	0	17,386	0	17,386	392	6,557	10,221	217	0
18	Total		360-363	716,539	290,257	422,465	28,137	394,328	308,234	75,963	9,903	228	3,817
	Overhead Lines												
19	Primary Capacity 1 Phase	D61PS1Ph		157,624	117,149	39,919	5,875	34,044	24,916	9,128	0	0	556
20	Primary Capacity Multi Phase	D61PS		339,139	123,659	214,380	11,428	202,953	163,958	38,995	0	0	1,100
21	Primary Customer 1 Phase	C61PS1Ph		84,558	80,543	3,808	3,268	541	533	8	0	0	207
22	Primary Customer Multi Phase	C61PS		181,932	162,266	18,886	12,131	6,755	6,689	66	0	0	780
23	Total Primary			763,253	483,616	276,994	32,702	244,292	196,096	48,196	0	0	2,643
24	Second Capacity	D62SecL		38,791	19,114	19,579	1,405	18,174	18,174	0	0	0	98
25	Second Customer	C62Sec		139,563	124,522	14,442	9,309	5,133	5,133	0	0	0	599
26	Total Secondary			178,354	143,636	34,021	10,714	23,307	23,307	0	0	0	697
27	Street Lighting	DASL		46,623	0	0	0	0	0	0	0	0	46,623
28	Total		364,365	988,231	627,253	311,015	43,416	267,599	219,402	48,196	0	0	49,963
	Underground Lines												
29	Primary Capacity 1 Phase	D61PS1Ph		271,332	201,659	68,716	10,113	58,603	42,891	15,712	0	0	957
30	Primary Capacity Multi Phase	D61PS		389,975	142,195	246,516	13,141	233,375	188,535	44,840	0	0	1,265
31	Primary Customer 1 Phase	C61PS1Ph		308,351	293,709	13,888	11,916	1,972	1,942	30	0	0	754
32	Primary Customer Multi Phase	C61PS		443,181	395,274	46,006	29,551	16,454	16,293	161	0	0	1,901
33	Total Primary			1,412,839	1,032,837	375,125	64,722	310,403	249,661	60,743	0	0	4,877
34	Second Capacity	D62SecL		45,452	22,396	22,941	1,646	21,295	21,295	0	0	0	115
35	Second Customer	C62Sec		127,778	114,007	13,223	8,523	4,699	4,699	0	0	0	548
36	Total Secondary			173,230	136,403	36,164	10,170	25,994	25,994	0	0	0	663
37	Street Lighting	DASL		0	0	0	0	0	0	0	0	0	0
38	Total		366,367	1,586,069	1,169,240	411,289	74,891	336,398	275,655	60,743	0	0	5,540
	Line Transformers												
39	Primary	D61PS		43,157	15,736	27,281	1,454	25,827	20,865	4,962	0	0	140
40	Second Capacity	D62SecL		128,844	63,486	65,031	4,667	60,365	60,365	0	0	0	326
41	Second Customer	C62Sec		226,264	201,879	23,414	15,093	8,321	8,321	0	0	0	971
42	Total		368	398,265	281,102	115,726	21,214	94,513	89,551	4,962	0	0	1,437
	Services												
43	Second Capacity	D62NLL		67,429	50,209	17,220	1,392	15,828	15,828	0	0	0	0
44	Second Customer	C62NL		220,538	209,306	11,232	7,240	3,992	3,992	0	0	0	0
43	Total Services	C62NL	369	287,967	259,515	28,452	8,632	19,820	19,820	0	0	0	0
44	Meters	C12WM	370	85,566	56,820	28,564	8,478	20,086	18,865	1,170	32	19	183
45	Street Lighting	Dir Assign	373	73,745	0	0	0	0	0	0	0	0	73,745
46	**Total Distribution**			4,136,381	2,684,186	1,317,510	184,768	1,132,742	931,527	191,034	9,934	247	134,685
47	**General & Common Plant**	PTD	303, 389-399	1,841,188	738,038	1,087,062	64,879	1,022,183	756,584	186,643	74,902	4,054	16,089
48	Prelim Elec Plant			20,817,953	8,344,847	12,291,194	733,569	11,557,625	8,554,553	2,110,338	846,900	45,834	181,912
49	TBT Investment	NEPIS		0	0	0	0	0	0	0	0	0	0
50	**Elec Plant in Serv**			20,817,953	8,344,847	12,291,194	733,569	11,557,625	8,554,553	2,110,338	846,900	45,834	181,912

Northern States Power Company

2021 Class Cost of Service Study Detail ($000)

Accum Deprec; Net Plant

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		1,396,686	536,986	859,699	47,689	812,011	608,666	145,283	54,878	3,183	0
2	Decom Int Peaking	D10S		0	0	0	0	0	0	0	0	0	0
3	Decom Int Baseload	E8760		0	0	0	0	0	0	0	0	0	0
4	Nuclear Fuel	E8760		2,359,851	703,812	1,647,923	74,689	1,573,235	1,132,833	294,878	139,422	6,101	8,115
5	Base Load	E8760		3,018,438	900,232	2,107,825	95,533	2,012,293	1,448,984	377,173	178,332	7,803	10,380
6	Total		108,111,115,120.5	6,774,974	2,141,031	4,615,448	217,910	4,397,538	3,190,484	817,335	372,632	17,087	18,495
	Transmission												
7	Gen Step Up Base	E8760		10,615	3,166	7,412	336	7,076	5,096	1,326	627	27	37
8	Gen Step Up Peak	D10S		14,243	5,476	8,767	486	8,281	6,207	1,482	560	32	0
9	Total Gen Step Up			24,858	8,642	16,179	822	15,357	11,303	2,808	1,187	60	37
10	Bulk Transmission	D10S		761,180	292,652	468,528	25,990	442,538	331,717	79,178	29,908	1,734	0
11	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign		1,898	0	1,898	0	1,898	317	0	0	1,581	0
13	Total		108,111,115,120.5	787,936	301,294	486,605	26,812	459,793	343,337	81,986	31,095	3,375	37
	Distribution												
14	Generat Step Up	STRATH		2,253	705	1,542	72	1,469	1,065	274	126	6	6
15	Bulk Transmission	D10S		657	253	404	22	382	286	68	26	1	0
16	Distrib Function	D60Sub		238,905	99,308	138,287	9,627	128,660	105,161	23,690	(191)	0	1,310
17	Direct Assign	Dir Assign		6,346	0	6,346	0	6,346	143	2,393	3,731	79	0
18	Total Substations			248,161	100,266	146,579	9,722	136,857	106,654	26,426	3,691	86	1,317
19	Overhead Lines	POL		355,467	225,623	111,872	15,617	96,255	78,919	17,336	0	0	17,972
20	Underground	PUL		479,353	353,376	124,303	22,634	101,668	83,310	18,358	0	0	1,674
21	Line Transformers	P68		174,667	123,283	50,754	9,304	41,450	39,274	2,176	0	0	630
22	Services	P69		177,215	159,705	17,509	5,312	12,197	12,197	0	0	0	0
23	Meters	C12WM		68,988	45,811	23,029	6,835	16,194	15,210	944	26	15	147
24	Street Lighting	P73		15,322	0	0	0	0	0	0	0	0	15,322
25	Total		108,111,115,120.5	1,519,172	1,008,064	474,046	69,424	404,622	335,565	65,240	3,716	101	37,062
26	**General & CommonPlant**	PTD	108,111,115,120.5	922,457	369,766	544,631	32,505	512,126	379,058	93,510	37,527	2,031	8,061
27	**Total Accum Depr**			10,004,539	3,820,155	6,120,730	346,651	5,774,079	4,248,444	1,058,071	444,970	22,594	63,654
28	**Net Elec Plant**			10,813,415	4,524,692	6,170,464	386,918	5,783,546	4,306,109	1,052,267	401,930	23,240	118,258
29	**Net Plant w/ TBT**			10,813,415	4,524,692	6,170,464	386,918	5,783,546	4,306,109	1,052,267	401,930	23,240	118,258

Subtractions: Accum Defer Inc Tax

				MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
	Production												
30	Peaking Plant	D10S		268,788	103,341	165,446	9,178	156,269	117,136	27,959	10,561	612	0
31	Base Load	E8760		921,482	274,827	643,486	29,165	614,322	442,352	115,145	54,442	2,382	3,169
32	Nuclear Fuel	E8760		(3,040)	(907)	(2,123)	(96)	(2,027)	(1,459)	(380)	(180)	(8)	(10)
33	Total		190,281,282,283	1,187,230	377,262	806,810	38,246	768,564	558,029	142,725	64,824	2,987	3,158
	Transmission												
34	Gen Step Up Base	E8760		15,020	4,480	10,489	475	10,014	7,210	1,877	887	39	52
35	Gen Step Up Peak	D10S		4,020	1,545	2,474	137	2,337	1,752	418	158	9	0
36	Total Gen Step Up			19,040	6,025	12,963	613	12,351	8,962	2,295	1,045	48	52
37	Bulk Transmission	D10S		707,910	272,172	435,739	24,171	411,568	308,503	73,637	27,815	1,613	0
38	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
39	Direct Assign	Dir Assign		1,194	0	1,194	0	1,194	199	0	0	994	0
40	Total		281,282,283	728,144	278,197	449,896	24,784	425,112	317,664	75,932	28,860	2,655	52
	Distribution												
41	Generat Step Up	STRATH		324	101	222	10	211	153	39	18	1	1
42	Bulk Transmission	D10S		247	95	152	8	144	108	26	10	1	0
43	Distrib Function	D60Sub		108,854	45,248	63,008	4,386	58,622	47,915	10,794	(87)	0	597
44	Direct Assign	Dir Assign		2,213	0	2,213	0	2,213	50	835	1,301	28	0
45	Total Substations			111,638	45,445	65,596	4,405	61,190	48,226	11,694	1,242	29	598
46	Overhead Lines	POL		150,543	95,553	47,379	6,614	40,765	33,423	7,342	0	0	7,611
47	Underground	PUL		234,114	172,587	60,709	11,054	49,654	40,688	8,966	0	0	818
48	Line Transformers	P68		56,322	39,753	16,366	3,000	13,366	12,664	702	0	0	203
49	Services	P69		18,607	16,768	1,838	558	1,281	1,281	0	0	0	0
50	Meters	C12WM		10,491	6,967	3,502	1,039	2,463	2,313	143	4	2	22
51	Street Lighting	P73		13,630	0	0	0	0	0	0	0	0	13,630
52	Total		281,282,283	595,346	377,074	195,390	26,671	168,719	138,595	28,847	1,246	31	22,882
53	**General & Common Plant**	PTD	281,282,283	138,474	55,507	81,757	4,879	76,877	56,902	14,037	5,633	305	1,210
54	**Total Deferred Tax**			2,649,194	1,088,039	1,533,852	94,580	1,439,272	1,071,190	261,541	100,563	5,978	27,302
55	Net Operating Loss (NOL) Carry F	NEPIS		(489,606)	(204,868)	(279,384)	(17,519)	(261,866)	(194,971)	(47,644)	(18,198)	(1,052)	(5,354)
56	Non-Plant Related	LABOR		28,051	10,957	16,817	1,041	15,776	11,647	2,883	1,189	57	278
57	**Accum Def W/ Adj**			2,187,638	894,128	1,271,284	78,102	1,193,182	887,867	216,780	83,553	4,983	22,226

Northern States Power Company

2021 Class Cost of Service Study Detail ($000)

Additions: CWIP, Etc; Rate Base

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		30,029	11,545	18,484	1,025	17,458	13,086	3,124	1,180	68	0
2	Base Load	E8760		74,469	22,210	52,003	2,357	49,646	35,748	9,305	4,400	193	256
3	Nuclear Fuel	E8760		96,871	28,891	67,647	3,066	64,581	46,503	12,105	5,723	250	333
4	Total		107	201,369	62,646	138,133	6,448	131,685	95,337	24,534	11,303	511	589
	Transmission												
5	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10S		386	149	238	13	225	168	40	15	1	0
7	Total Gen Step Up			386	149	238	13	225	168	40	15	1	0
8	Bulk Transmission	D10S		74,831	28,770	46,060	2,555	43,505	32,611	7,784	2,940	171	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
11	Total		107	75,217	28,919	46,298	2,568	43,730	32,779	7,824	2,955	171	0
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub		10,014	4,163	5,796	404	5,393	4,408	993	(8)	0	55
15	Direct Assign	Dir Assign		20	0	20	0	20	0	8	12	0	0
16	Total Substations			10,034	4,163	5,817	404	5,413	4,408	1,001	4	0	55
17	Overhead Lines	POL		17,267	10,960	5,434	759	4,676	3,834	842	0	0	873
18	Underground	PUL		33,242	24,506	8,620	1,570	7,051	5,777	1,273	0	0	116
19	Line Transformers	P68		928	655	270	49	220	209	12	0	0	3
20	Services	P69		138	125	14	4	10	10	0	0	0	0
21	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
23	Total		107	61,610	40,408	20,155	2,785	17,369	14,238	3,128	4	0	1,047
24	**General & Common Plant**	PTD	107	79,608	31,911	47,001	2,805	44,196	32,713	8,070	3,239	175	696
25	**Total CWIP**			417,804	163,884	251,587	14,607	236,981	175,066	43,555	17,501	858	2,332
26	Fuel Inventory	E8760	151,152	65,875	19,647	46,001	2,085	43,916	31,623	8,231	3,892	170	227
	Materials & Supplies												
27	Production	P10		137,523	43,610	93,543	4,428	89,116	64,685	16,554	7,530	346	369
28	Trans & Distr	TD		16,409	8,682	7,431	655	6,777	5,249	1,186	314	28	295
29	Total		154	153,932	52,292	100,975	5,082	95,892	69,934	17,740	7,843	374	665
	Prepayments												
30	Miscellaneous	NEPIS		92,118	38,545	52,565	3,296	49,269	36,683	8,964	3,424	198	1,007
31	Fuel	E8760		0	0	0	0	0	0	0	0	0	0
32	Insurance	NEPIS	135,143,184,186,232	0	0	0	0	0	0	0	0	0	0
33	Total		235,252,165	92,118	38,545	52,565	3,296	49,269	36,683	8,964	3,424	198	1,007
34	Non-Plant Assets & Liab	LABOR	190,283,	81,070	31,665	48,601	3,008	45,593	33,662	8,333	3,435	163	804
35	Working Cash	PT0	calculated	(127,030)	(54,198)	(71,517)	(4,593)	(66,924)	(49,928)	(12,129)	(4,600)	(266)	(1,316)
36	**Total Additions**			683,768	251,836	428,213	23,485	404,728	297,040	74,694	31,495	1,498	3,719
37	**Total Rate Base**			9,309,544	3,882,400	5,327,393	332,301	4,995,091	3,715,283	910,181	349,872	19,755	99,751
38	**Common Rate Base (@ 52.50%)**			4,887,510.5	2,038,260	2,796,881	174,458	2,622,423	1,950,523	477,845	183,683	10,372	52,369

Northern States Power Company

2021 Class Cost of Service Study Detail ($000)

	Operating Rev (Cal Month)			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Retail Revenue	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Present Rate Revenue	R01; (calc)	440, 442,444,445	3,080,208	1,148,029	1,905,512	108,275	1,797,236	1,348,907	307,387	133,692	7,250	26,668
2	Proposed Rate Revenue	PROREV; (calc)		3,426,848	1,299,084	2,096,834	122,225	1,974,609	1,481,169	339,826	145,785	7,830	30,930
3	Equal Rate Revenue			3,426,848	1,308,331	2,087,171	121,389	1,965,782	1,449,685	360,199	148,393	7,505	31,346
	Other Retail Revenue												
4	Interdepartmental	R01; R02	448	736	274	455	26	430	322	73	32	2	6
5	Gross Earnings Tax	R01; R02	408	0	0	0	0	0	0	0	0	0	0
6	CIP Adjustment to Program Costs	E99XCIP	456	0	0	0	0	0	0	0	0	0	0
7	**Tot Other Retail Rev**			736	274	455	26	430	322	73	32	2	6
	Other Operating Revenue												
8	Interchg Prod Capacity	P10	456	428,299	135,818	291,330	13,789	277,541	201,456	51,557	23,450	1,079	1,151
9	Interchg Prod Energy	E8760	456	0	0	0	0	0	0	0	0	0	0
10	Interchg Tr Bulk Supply	D10S	456	(9,521)	(3,660)	(5,860)	(325)	(5,535)	(4,149)	(990)	(374)	(22)	0
11	Dist Int Sales; Oth Serv	E8760	412,451,456	630	188	440	20	420	303	79	37	2	2
12	Dist Overhd Line Rent	POL	454	5,006	3,177	1,575	220	1,356	1,111	244	0	0	253
13	Connection Charges	C11	451	1,930	1,693	197	126	70	70	1	0	0	40
14	Sales For Resale	E8760	447	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
15	Joint Op Agree-Other PSCo Rev	D10S	456	0	0	0	0	0	0	0	0	0	0
16	Misc Ancillary Trans Rev	D10S		204,100	78,471	125,629	6,969	118,661	88,946	21,231	8,019	465	0
17	MISO	D10S	456	(90,113)	(34,646)	(55,467)	(3,077)	(52,390)	(39,271)	(9,374)	(3,541)	(205)	0
18	Other	D10S	451,456,457	14,220	5,467	8,753	486	8,267	6,197	1,479	559	32	0
19	Late Pay Chg - Pres	R16C; R02		5,687	4,895	787	321	466	441	24	1	1	5
20	**Tot Other Op - Pres**		450	560,238	191,403	367,384	18,530	348,855	255,103	64,250	28,151	1,351	1,451
21	Incr Misc Serv - Prop	R01,		447	167	277	16	261	196	45	19	1	4
22	Incr Inter-Dept'l - Prop	R01; R02		67	25	42	2	39	29	7	3	0	1
23	Incr Late Pay - Prop	(R16C); R02		640	551	89	36	52	50	3	0	0	1
	Tot Incr Other Op			1,154	743	407	54	353	275	54	22	1	5
24	**Tot Other Op - Prop**			561,393	192,145	367,791	18,584	349,207	255,378	64,304	28,173	1,353	1,456
25	**Tot Oper Rev - Pres**			3,641,182	1,339,706	2,273,352	126,831	2,146,521	1,604,333	371,710	161,875	8,603	28,125
26	**Tot Oper Rev - Prop**			3,988,977	1,491,504	2,465,081	140,835	2,324,246	1,736,869	404,203	173,990	9,184	32,392
	Tot Oper Rev - Eql			3,988,977	1,500,751	2,455,418	139,999	2,315,419	1,705,386	424,576	176,598	8,860	32,808
	Operating & Maint (Pg 1 of 2)												
	Production Expen												
27	**Fuel**	E8760	501,518,547	649,247	193,634	453,380	20,548	432,832	311,668	81,128	38,358	1,678	2,233
	Purchased Power												
28	Purchases: Cap Peak	D10S		98,827	37,996	60,831	3,374	57,456	43,068	10,280	3,883	225	0
29	Purchases: Cap Base	D10S		36,775	14,139	22,636	1,256	21,380	16,026	3,825	1,445	84	0
30	Purchases: Demand		555	135,602	52,135	83,467	4,630	78,837	59,094	14,105	5,328	309	0
31	Purchases: Other Energy	E8760	555	288,737	86,114	201,630	9,138	192,491	138,606	36,079	17,059	746	993
32	Tot Non-Assoc Purch			424,339	138,249	285,096	13,768	271,328	197,701	50,185	22,387	1,055	993
33	Interchg Agr Capacity	P10WoN	557	39,885	12,861	26,925	1,290	25,635	18,651	4,749	2,135	100	99
34	Interchg Agr Energy	E8760	557	15,635	4,663	10,918	495	10,424	7,506	1,954	924	40	54
35	Tot Wis Interchg Purch			55,521	17,524	37,844	1,785	36,059	26,157	6,703	3,059	140	152
36	**Tot Purchased Power**			479,859	155,774	322,940	15,554	307,387	223,858	56,888	25,445	1,196	1,145
	Other Production		500,502,505-507 509-514,517-519,520,										
37	Capacity Related	D10S	523-525,528-532,535,	96,876	37,246	59,630	3,308	56,322	42,218	10,077	3,806	221	0
38	Energy Related	E8760	539,543-546,548-550	351,128	104,722	245,199	11,113	234,085	168,557	43,876	20,745	908	1,207
39	Total Other Produc	21.62%	552-554,556,557 575.1-575.8	448,003.864	141,968	304,828	14,421	290,408	210,775	53,953	24,551	1,129	1,207
40	**Total Production**			1,577,110	491,376	1,081,149	50,523	1,030,626	746,300	191,968	88,355	4,003	4,585
41	**Transmission Exp**	D10S	560-563, 565-568 570-573	249,696	96,001	153,695	8,526	145,170	108,816	25,973	9,811	569	0

Northern States Power Company

Docket No. E002/GR-19-564

2021 Class Cost of Service Study Detail ($000)

Operating & Maint (Pg 2 of 2)

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Distribution Expen	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Supervision & Eng'rg	ZDTS	580,590	7,015	4,039	2,670	326	2,345	1,881	406	55	3	306
2	Load Dispatching	T20D80	581	7,395	3,028	4,335	289	4,046	3,248	740	53	3	32
3	Substations	P61	582,591,592	9,205	3,729	5,427	361	5,066	3,960	976	127	3	49
4	Overhead Lines	POL	583,593	44,053	27,961	13,864	1,935	11,929	9,780	2,148	0	0	2,227
5	Underground Lines	PUL	584, 594	15,820	11,662	4,102	747	3,355	2,749	606	0	0	55
6	Line Transformers	P68	595	1,405	991	408	75	333	316	17	0	0	5
7	Meters	C12WM	586,597,598	5,828	3,870	1,945	577	1,368	1,285	80	2	1	12
8	Customer Install'n	OXDTS	587	3,865	2,308	1,347	179	1,168	955	205	8	0	210
9	Street Lighting	Dir Assign	585,596	2,299	0	0	0	0	0	0	0	0	2,299
10	Miscellaneous	OXDTS	588	31,895	19,050	11,114	1,475	9,639	7,882	1,689	65	3	1,731
11	Rents (Pole Attachmts)	POL	589	3,360	2,133	1,058	148	910	746	164	0	0	170
12	**Total Distribution**			132,140	78,771	46,271	6,112	40,159	32,804	7,031	310	13	7,098
13	**Customer Accounting**	C11WA	901-905	48,931	40,617	8,119	4,551	3,568	3,514	51	2	1	195
14	**Sales, Econ Dvlp & Other**	R01	912	(5)	(2)	(3)	(0)	(3)	(2)	(1)	(0)	(0)	(0)
	Admin & General												
15	Salaries	LABOR	920	74,547	29,117	44,690	2,766	41,924	30,953	7,662	3,158	150	739
16	Office Supplies	OXTS	921	50,072	17,745	32,013	1,744	30,269	22,196	5,570	2,390	114	314
17	Admin Transfer Credit	OXTS	922	(40,981)	(14,523)	(26,201)	(1,427)	(24,774)	(18,166)	(4,559)	(1,956)	(94)	(257)
18	Outside Services	LABOR	923	22,264	8,696	13,347	826	12,521	9,244	2,288	943	45	221
19	Property Insurance	NEPIS	924	6,485	2,714	3,701	232	3,468	2,582	631	241	14	71
20	Pensions & Benefits	LABOR	926	78,336	30,597	46,962	2,907	44,055	32,527	8,052	3,319	158	777
21	Injuries & Claims	LABOR	925	12,126	4,736	7,270	450	6,820	5,035	1,246	514	24	120
22	Regulatory Exp	R01; R02	928	5,179	1,930	3,204	182	3,022	2,268	517	225	12	45
23	General Advertising	OXTS	930.1	234	83	149	8	141	104	26	11	1	1
24	Contributions	OXTS		0	0	0	0	0	0	0	0	0	0
25	Misc General Exp	OXTS	929, 930.2	(314)	(111)	(201)	(11)	(190)	(139)	(35)	(15)	(1)	(2)
26	Rents	OXTS	931	43,543	15,431	27,839	1,516	26,323	19,302	4,844	2,078	99	273
27	Maint of General Plant	OXTS	935	779	276	498	27	471	345	87	37	2	5
28	Total			252,269	96,691	153,271	9,220	144,051	106,251	26,329	10,946	525	2,307
	Cust Service & Info												
29	Cust Assist Exp - Non-CIP	C11P10	908	2,288	1,366	895	112	783	579	138	63	3	27
30	CIP Total	E99XCIP	908	102,371.401	31,534	70,375	3,202	67,173	51,362	11,910	3,605	296	462
31	Instructional Advertising	C11P10	909	873	521	341	43	299	221	53	24	1	10
32	Total			105,532	33,421	71,611	3,356	68,255	52,162	12,101	3,692	300	499
33	Amortizations	LABOR		43,475	16,981	26,063	1,613	24,450	18,052	4,469	1,842	88	431
34	**Total O&M Expense**			2,409,148	853,857	1,540,176	83,901	1,456,275	1,067,897	267,922	114,958	5,499	15,115

2021 Class Cost of Service Study Detail ($000)

Book Depreciation

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		103,652	39,851	63,801	3,539	60,262	45,171	10,782	4,073	236	0
2	Base Load	E8760		305,366	91,074	213,242	9,665	203,578	146,589	38,157	18,041	789	1,050
3	Total		403,413	409,019	130,925	277,043	13,204	263,840	191,760	48,939	22,114	1,026	1,050
	Transmission												
4	Gen Step Up Base	E8760		1,489	444	1,040	47	993	715	186	88	4	5
5	Gen Step Up Peak	D10S		854	328	526	29	497	372	89	34	2	0
6	Total Gen Step Up			2,343	773	1,566	76	1,489	1,087	275	122	6	5
7	Bulk Transmission	D10S		67,399	25,913	41,486	2,301	39,185	29,372	7,011	2,648	154	0
8	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
9	Direct Assign	Dir Assign		124	0	124	0	124	21	0	0	103	0
10	Total		403,413	69,867	26,686	43,176	2,378	40,798	30,480	7,286	2,770	263	5
	Distribution												
11	Generat Step Up	STRATH		68	21	47	2	45	32	8	4	0	0
12	Bulk Transmission	D10S		40	15	24	1	23	17	4	2	0	0
13	Distrib Function	D60Sub		15,709	6,530	9,093	633	8,460	6,915	1,558	(13)	0	86
14	Direct Assign	Dir Assign		383	0	383	0	383	9	144	225	5	0
15	Total Substations		403,413	16,200	6,567	9,547	637	8,910	6,973	1,714	218	5	86
16	Overhead Lines	POL		34,449	21,866	10,842	1,513	9,328	7,648	1,680	0	0	1,742
17	Underground	PUL		39,378	29,029	10,211	1,859	8,352	6,844	1,508	0	0	138
18	Line Transformers	P68		10,884	7,682	3,163	580	2,583	2,447	136	0	0	39
19	Services	P69		10,422	9,392	1,030	312	717	717	0	0	0	0
20	Meters	C12WM		3,886	2,581	1,297	385	912	857	53	1	1	8
21	Street Lighting	P73		3,981	0	0	0	0	0	0	0	0	3,981
22	Total		403,413	119,199	77,116	36,089	5,287	30,803	25,486	5,091	219	6	5,994
23	**General & Common Plant**	PTD	403,413	121,439	48,679	71,699	4,279	67,420	49,902	12,310	4,940	267	1,061
24	**Total Book Deprec**		403,404	719,524	283,406	428,008	25,147	402,861	297,629	73,627	30,043	1,562	8,110

Real Estate & Property Tax

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
25	Peaking Plant	D10S		25,834	9,933	15,902	882	15,020	11,258	2,687	1,015	59	0
26	Base Load	E8760		66,166	19,734	46,205	2,094	44,110	31,762	8,268	3,909	171	228
27	Total		408.1	92,000	29,666	62,106	2,976	59,130	43,021	10,955	4,924	230	228
	Transmission												
28	Gen Step Up Base	E8760		1,030.5229	307	720	33	687	495	129	61	3	4
29	Gen Step Up Peak	D10S		431.1112	166	265	15	251	188	45	17	1	0
30	Total Gen Step Up			1,461.6340	473	985	47	938	683	174	78	4	4
31	Bulk Transmission	D10S		38,705.9909	14,881	23,825	1,322	22,503	16,868	4,026	1,521	88	0
32	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
33	Direct Assign	Dir Assign		71	0	71	0	71	12	0	0	59	0
34	Total		408.1	40,238.864	15,354	24,881	1,369	23,512	17,562	4,200	1,599	151	4
	Distribution												
35	Generat Step Up	STRATH		38	12	26	1	25	18	5	2	0	0
36	Bulk Transmission	D10S		22	8	13	1	13	9	2	1	0	0
37	Distrib Function	D60Sub		8,609	3,579	4,983	347	4,636	3,790	854	(7)	0	47
38	Direct Assign	Dir Assign		216	0	216	0	216	5	81	127	3	0
39	Total Substations			8,884	3,599	5,238	349	4,889	3,822	942	123	3	47
40	Overhead Lines	POL		12,253	7,777	3,856	538	3,318	2,720	598	0	0	619
41	Underground	PUL		19,665	14,497	5,099	929	4,171	3,418	753	0	0	69
42	Line Transformers	P68		4,938	3,485	1,435	263	1,172	1,110	62	0	0	18
43	Services	P69		3,570	3,218	353	107	246	246	0	0	0	0
44	Meters	C12WM		1,061	704	354	105	249	234	15	0	0	2
45	Street Lighting	P73		914	0	0	0	0	0	0	0	0	914
46	Total		408.1	51,286	33,280	16,335	2,291	14,044	11,550	2,369	123	3	1,670
47	**General & Common Plant**	PTD	408.1	0	0	0	0	0	0	0	0	0	0
48	**Tot Rl Est & Pr Tax**			183,524	78,301	103,322	6,636	96,686	72,133	17,523	6,646	384	1,901
49	Gross Earnings Tax	R01; R02		0	0	0	0	0	0	0	0	0	0
50	Payroll Taxes	LABOR		27,352	10,683	16,397	1,015	15,382	11,357	2,811	1,159	55	271
51	**Tot Non-Inc Taxes**			210,876	88,984	119,720	7,651	112,069	83,490	20,335	7,805	439	2,172

2021 Class Cost of Service Study Detail ($000)

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

Provision For Defer Inc Tax

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		(5,518)	(2,121)	(3,396)	(188)	(3,208)	(2,405)	(574)	(217)	(13)	0
2	Nuclear Fuel	E8760		(3,042)	(907)	(2,124)	(96)	(2,028)	(1,460)	(380)	(180)	(8)	(10)
3	Base Load	E8760		6,994	2,086	4,884	221	4,663	3,357	874	413	18	24
4	Total		410, 411	(1,566)	(943)	(636)	(63)	(573)	(507)	(80)	17	(2)	14
	Transmission												
5	Gen Step Up Base	E8760		589	176	412	19	393	283	74	35	2	2
6	Gen Step Up Peak	D10S		216	83	133	7	126	94	22	8	0	0
7	Total Gen Step Up			805	259	545	26	519	377	96	43	2	2
8	Bulk Transmission	D10S		8,468	3,256	5,212	289	4,923	3,690	881	333	19	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		10	0	10	0	10	2	0	0	8	0
11	Total		410, 411	9,283	3,515	5,767	315	5,451	4,069	977	376	29	2
	Distribution												
12	Generat Step Up	STRATH		(27)	(9)	(19)	(1)	(18)	(13)	(3)	(2)	(0)	(0)
13	Bulk Transmission	D10S		(8)	(3)	(5)	(0)	(4)	(3)	(1)	(0)	(0)	0
14	Distrib Function	D60Sub		(906)	(377)	(524)	(37)	(488)	(399)	(90)	1	0	(5)
15	Direct Assign	Dir Assign		(53)	0	(53)	0	(53)	(1)	(20)	(31)	(1)	0
16	Total Substations			(994)	(388)	(601)	(38)	(564)	(416)	(114)	(32)	(1)	(5)
17	Overhead Lines	POL		1,007	639	317	44	273	223	49	0	0	51
18	Underground	PUL		(2,803)	(2,067)	(727)	(132)	(595)	(487)	(107)	0	0	(10)
19	Line Transformers	P68		(2,497)	(1,763)	(726)	(133)	(593)	(562)	(31)	0	0	(9)
20	Services	P69		(1,037)	(934)	(102)	(31)	(71)	(71)	0	0	0	0
21	Meters	C12WM		(472)	(313)	(158)	(47)	(111)	(104)	(6)	(0)	(0)	(1)
22	Street Lighting	P73		(404)	0	0	0	0	0	0	0	0	(404)
23	Total		410, 411	(7,202)	(4,826)	(1,997)	(337)	(1,660)	(1,417)	(210)	(33)	(1)	(378)
24	**General & Common Plant**	PTD	410, 411	(3,513)	(1,408)	(2,074)	(124)	(1,950)	(1,443)	(356)	(143)	(8)	(31)
25	**Net Operating Loss (NOL) Carry**	NEPIS		(172,039)	(71,987)	(98,171)	(6,156)	(92,015)	(68,509)	(16,741)	(6,395)	(370)	(1,881)
26	**Non - Plant Related**	LABOR	410, 411	3,587	1,401	2,150	133	2,017	1,489	369	152	7	36
27	**Tot Prov For Defer**			(171,449)	(74,248)	(94,961)	(6,231)	(88,730)	(66,319)	(16,042)	(6,025)	(344)	(2,239)

Inv Tax Credit; Total Oper Exp

				MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
	Production												
28	Peaking Plant	D10S		(260)	(100)	(160)	(9)	(151)	(113)	(27)	(10)	(1)	0
29	Base Load	E8760		(538)	(160)	(376)	(17)	(359)	(258)	(67)	(32)	(1)	(2)
30	Total		411	(798)	(260)	(536)	(26)	(510)	(372)	(94)	(42)	(2)	(2)
	Transmission												
31	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
32	Gen Step Up Peak	D10S		0	0	0	0	0	0	0	0	0	0
33	Total Gen Step Up			0	0	0	0	0	0	0	0	0	0
34	Bulk Transmission	D10S		(150)	(58)	(92)	(5)	(87)	(65)	(16)	(6)	(0)	0
35	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
36	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
37	Total		411	(150)	(58)	(92)	(5)	(87)	(65)	(16)	(6)	(0)	0
	Distribution												
38	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
39	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
40	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
41	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
42	Total Substations			0	0	0	0	0	0	0	0	0	0
43	Overhead Lines	POL		(268)	(170)	(84)	(12)	(73)	(60)	(13)	0	0	(14)
44	Underground	PUL		0	0	0	0	0	0	0	0	0	0
45	Line Transformers	P68		0	0	0	0	0	0	0	0	0	0
46	Services	P69		0	0	0	0	0	0	0	0	0	0
47	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
48	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
49	Total		411	(268)	(170)	(84)	(12)	(73)	(60)	(13)	0	0	(14)
50	**General & Common Plant**	PTD	411	(7)	(3)	(4)	(0)	(4)	(3)	(1)	(0)	(0)	(0)
51	**Net Inv Tax Credit**			(1,223)	(491)	(717)	(43)	(673)	(499)	(124)	(48)	(2)	(15)
52	**Total Operating Exp**			**3,166,876**	**1,151,508**	**1,992,226**	**110,425**	**1,881,801**	**1,382,197**	**345,718**	**146,732**	**7,153**	**23,143**
53A	**Pres Op Inc Before Inc Tax**			**474,306**	**188,198**	**281,126**	**16,406**	**264,720**	**222,136**	**25,992**	**15,143**	**1,450**	**4,982**
53B	**Prop Op Inc Before Inc Tax**			**822,101**	**339,996**	**472,855**	**30,410**	**442,446**	**354,672**	**58,485**	**27,258**	**2,031**	**9,249**

2021 Class Cost of Service Study Detail ($000) Page 11 of 14

Tax Deprec; Inc Tax & Return

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		107,112	41,182	65,931	3,657	62,273	46,679	11,142	4,209	244	0
2	Nuclear Fuel	E8760		94,243	28,107	65,811	2,983	62,829	45,241	11,776	5,568	244	324
3	Base Load	E8760		419,862	125,222	293,197	13,289	279,908	201,553	52,464	24,806	1,085	1,444
4	Total		tax books	621,218	194,511	424,939	19,929	405,010	293,472	75,383	34,582	1,573	1,768
	Transmission												
5	Gen Step Up Base	E8760		3,916	1,168	2,735	124	2,611	1,880	489	231	10	13
6	Gen Step Up Peak	D10S		1,534	590	944	52	892	668	160	60	3	0
7	Total Gen Step Up			5,450	1,758	3,679	176	3,503	2,548	649	292	14	13
8	Bulk Transmission	D10S		105,711	40,643	65,068	3,609	61,459	46,068	10,996	4,154	241	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		175	0	175	0	175	29	0	0	146	0
11	Total		tax books	111,336	42,401	68,922	3,786	65,136	48,646	11,645	4,445	400	13
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		14	5	9	0	8	6	1	1	0	0
14	Distrib Function	D60Sub		14,773	6,141	8,551	595	7,956	6,503	1,465	(12)	0	81
15	Direct Assign	Dir Assign		266	0	266	0	266	6	100	156	3	0
16	Total Substations			15,053	6,146	8,826	596	8,230	6,515	1,567	145	3	81
17	Overhead Lines	POL		37,522	23,816	11,809	1,648	10,160	8,330	1,830	0	0	1,897
18	Underground	PUL		39,143	28,856	10,150	1,848	8,302	6,803	1,499	0	0	137
19	Line Transformers	P68		8,119	5,730	2,359	432	1,927	1,826	101	0	0	29
20	Services	P69		7,552	6,806	746	226	520	520	0	0	0	0
21	Meters	C12WM		2,256	1,498	753	224	530	497	31	1	0	5
22	Street Lighting	P73		3,086	0	0	0	0	0	0	0	0	3,086
23	Total		tax books	112,730	72,853	34,643	4,975	29,668	24,491	5,028	146	4	5,234
24	**General & Common Plant**	PTD	tax books	138,561	55,542	81,808	4,883	76,926	56,938	14,046	5,637	305	1,211
25	Net Operating Loss (NOL) Carry F	NEPIS		0	0	0	0	0	0	0	0	0	0
26	**Total Tax Deprec**			983,845	365,306	610,313	33,572	576,741	423,547	106,101	44,810	2,282	8,227
27	Interest Expense		427,431	194,569.47	81,142	111,343	6,945	104,397	77,649	19,023	7,312	413	2,085
28	Other Tax Timing Differ	LABOR		3,725	1,455	2,233	138	2,095	1,547	383	158	8	37
29	Meals & Enter	LABOR		584	228	350	22	328	242	60	25	1	6
30	Total Tax Deductions			1,182,723	448,131	724,238	40,677	683,561	502,985	125,567	52,305	2,704	10,354
	Inc Tax Additions												
31	Book Depreciation			719,524	283,406	428,008	25,147	402,861	297,629	73,627	30,043	1,562	8,110
32	Deferred Inc Tax & ITC			(172,671.72)	(74,739)	(95,678)	(6,274)	(89,403)	(66,818)	(16,165)	(6,074)	(346)	(2,254)
33	Nuclear Fuel Book Burn	E8760		102,794	30,658	71,783	3,253	68,529	49,346	12,845	6,073	266	353
34	Tax Capitalized Leases	PTD		41,788	16,751	24,672	1,472	23,200	17,172	4,236	1,700	92	365
35	Avoided Tax Interest	RTBASE		18,089	7,544	10,352	646	9,706	7,219	1,769	680	38	194
36	Total Tax Additions			709,523	263,618	439,137	24,244	414,892	304,547	76,311	32,423	1,611	6,768
37	**Total Inc Tax Adjustments**			(473,200)	(184,513)	(285,101)	(16,432)	(268,669)	(198,438)	(49,256)	(19,883)	(1,093)	(3,586)
38A	**Pres Taxable Net Income**			1,106	3,685	(3,975)	(26)	(3,949)	23,697	(23,264)	(4,740)	357	1,396
38B	**Prop Taxable Net Income**			348,901	155,484	187,754	13,977	173,777	156,233	9,229	7,375	939	5,663
39A	Pres Fed & State Inc Tax			59,576	25,772	32,768	2,108	30,661	30,460	(893)	865	228	1,036
39B	Prop Fed & State Inc Tax			159,540	69,402	87,875	6,133	81,742	68,554	8,446	4,347	396	2,263
40A	Pres Preliminary Return	(total); BASE		414,729	162,426	248,358	14,298	234,060	191,675	26,885	14,278	1,221	3,946
40B	Prop Preliminary Return	(total); BASE		662,561	270,594	384,980	24,277	360,703	286,118	50,039	22,911	1,636	6,986
41	Total AFUDC			31,000	12,055	18,796	1,075	17,721	13,105	3,253	1,296	67	148
42A	**Present Total Return**			445,729	174,481	267,154	15,373	251,780	204,780	30,138	15,574	1,289	4,094
42B	**Proposed Total Return**			693,561	282,650	403,777	25,352	378,424	299,223	53,291	24,207	1,703	7,135
43A	**Pres % Return on Rate Base**			4.79%	4.49%	5.01%	4.63%	5.04%	5.51%	3.31%	4.45%	6.52%	4.10%
43B	**Prop % Return on Rate Base**			7.45%	7.28%	7.58%	7.63%	7.58%	8.05%	5.86%	6.92%	8.62%	7.15%
44A	**Present Common Return**			251,160	93,339	155,811	8,428	147,383	127,131	11,115	8,262	876	2,009
44B	**Proposed Common Return**			498,992	201,508	292,434	18,407	274,027	221,573	34,269	16,895	1,290	5,050
45A	**Pres % Ret on Common Rt Base**			5.14%	4.58%	5.57%	4.83%	5.62%	6.52%	2.33%	4.50%	8.44%	3.84%
45B	**Prop % Ret on Common Rt Base**			10.21%	9.89%	10.46%	10.55%	10.45%	11.36%	7.17%	9.20%	12.44%	9.64%

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Northern States Power Company Docket No. E002/GR-19-564

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Allow For Funds Used During Constr												
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		2,108	810	1,297	72	1,225	918	219	83	5	0
2	Nuclear Fuel	E8760		6,658	1,986	4,650	211	4,439	3,196	832	393	17	23
3	Base Load	E8760		6,298	1,878	4,398	199	4,199	3,023	787	372	16	22
4	Total		419.1,432	15,064	4,674	10,345	482	9,863	7,138	1,838	848	38	45
	Transmission												
5	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10S		415	159	255	14	241	181	43	16	1	0
7	Total Gen Step Up			415	159	255	14	241	181	43	16	1	0
8	Bulk Transmission	D10S		7,189	2,764	4,425	245	4,180	3,133	748	282	16	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		4	0	4	0	4	1	0	0	4	0
11	Total		419.1,432	7,608	2,924	4,685	260	4,425	3,315	791	299	21	0
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub		1,149	478	665	46	619	506	114	(1)	0	6
15	Direct Assign	Dir Assign		2	0	2	0	2	0	1	1	0	0
16	Total Substations			1,151	478	667	46	621	506	115	0	0	6
17	Overhead Lines	POL		1,147	728	361	50	311	255	56	0	0	58
18	Underground	PUL		2,142	1,579	555	101	454	372	82	0	0	7
19	Line Transformers	P68		0	0	0	0	0	0	0	0	0	0
20	Services	P69		228	206	23	7	16	16	0	0	0	0
21	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
23	Total		419.1,432	4,669	2,991	1,606	205	1,401	1,149	253	0	0	72
24	**General & Common Plant**	PTD	419.1,432	3,659	1,467	2,161	129	2,032	1,504	371	149	8	32
25	**Total AFUDC**			31,000	12,055	18,796	1,075	17,721	13,105	3,253	1,296	67	148
	Labor Allocator												
	Production												
26	Other Prod - Cap	D10S		62,298	23,952	38,346	2,127	36,219	27,149	6,480	2,448	142	0
27	Other Prod - Ene	E8760		159,555	47,586	111,420	5,050	106,370	76,593	19,937	9,427	412	549
28	Total		500 through 557	221,853	71,538	149,766	7,177	142,589	103,742	26,418	11,874	554	549
	Transmission												
29	Stepup Subtrans	P5161A		776	251	523	25	498	362	92	41	2	2
30	Bulk Power Subs	D10S		20,551	7,901	12,650	702	11,948	8,956	2,138	807	47	0
31	Total		560 through 571	21,327	8,152	13,173	727	12,446	9,319	2,230	849	49	2
	Distribution												
32	Superv & Eng	ZDTS	580, 590	6,110	3,518	2,326	284	2,042	1,639	353	48	2	267
33	Load Dispatch	D10S	581	6,805	2,616	4,189	232	3,956	2,966	708	267	16	0
34	Substation	P61	582, 592	6,036	2,445	3,559	237	3,322	2,597	640	83	2	32
35	Overhead Lines	POL	583, 593	10,867	6,898	3,420	477	2,943	2,413	530	0	0	549
36	Underground Lines	PUL	584, 594	10,202	7,521	2,646	482	2,164	1,773	391	0	0	36
37	Line Transformer	P68	595	1,189	839	346	63	282	267	15	0	0	4
38	Meter	C12WM	586, 597	3,554	2,360	1,187	352	834	784	49	1	1	8
39	Cust Installation	ZDTS	587	3,530	2,032	1,344	164	1,180	947	204	27	1	154
40	Street Lighting	P73	585, 596	1,023	0	0	0	0	0	0	0	0	1,023
41	Miscellaneous	OXDTS	588	7,542	4,505	2,628	349	2,279	1,864	399	15	1	409
42	Total			56,860	32,734	21,643	2,641	19,002	15,248	3,289	443	23	2,483
43	**Cust Accounting**	C11WA	901,902,903,904,905	10,285	8,538	1,707	957	750	739	11	0	0	41
44	**Sales Expense**	C11P10	912	0	0	0	0	0	0	0	0	0	0
45	**Admin & General**	LABOR	920,921,922,923,924,	154,012	60,156	92,329	5,715	86,614	63,949	15,830	6,525	310	1,527
46	**Service & Inform**	C11P10	908, 909	1,202	718	470	59	411	304	73	33	2	14
47	**Labor**			465,539	181,836	279,088	17,275	261,813	193,301	47,850	19,725	938	4,615

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HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	
INTERNAL ALLOCATORS		Intern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	50% Cus, 50% Prod Plt	C11P10	100.00%	59.72%	39.11%	4.89%	34.22%	25.32%	6.04%	2.74%	0.13%	1.18%
2	Peaking Plant Capacity	D10S	100.00%	38.45%	61.55%	3.41%	58.14%	43.58%	10.40%	3.93%	0.23%	0.00%
3	57% Dmd; 43% Energy: Sales & I	D57E43	100.00%	29.82%	69.83%	3.16%	66.67%	48.00%	12.50%	5.91%	0.26%	0.34%
4	40% Dmd; 60% Energy: CIP	D40E60	100.00%	29.82%	69.83%	3.16%	66.67%	48.00%	12.50%	5.91%	0.26%	0.34%
5	20%D10T; 80%D60Sub	T20D80	100.00%	40.94%	58.62%	3.91%	54.71%	43.93%	10.01%	0.72%	0.05%	0.44%
6	Labor w/o (or w/) A&G	LABOR	100.00%	39.06%	59.95%	3.71%	56.24%	41.52%	10.28%	4.24%	0.20%	0.99%
7	Net Plant In Service	NEPIS	100.00%	41.84%	57.06%	3.58%	53.48%	39.82%	9.73%	3.72%	0.21%	1.09%
8	Dis O&M w/o Sup & Misc	OXDTS	100.00%	59.73%	34.85%	4.62%	30.22%	24.71%	5.29%	0.20%	0.01%	5.43%
9	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	100.00%	35.44%	63.93%	3.48%	60.45%	44.33%	11.12%	4.77%	0.23%	0.63%
10	Production Plant	P10	100.00%	31.71%	68.02%	3.22%	64.80%	47.04%	12.04%	5.48%	0.25%	0.27%
11	Production Plant Wo Nuclear	P10WoN	100.00%	32.25%	67.51%	3.24%	64.27%	46.76%	11.91%	5.35%	0.25%	0.25%
12	Total P51 & P61A	P5161A	100.00%	32.34%	67.41%	3.24%	64.18%	46.71%	11.88%	5.33%	0.25%	0.24%
13	Distribution Plant	P60	100.00%	64.89%	31.85%	4.47%	27.38%	22.52%	4.62%	0.24%	0.01%	3.26%
14	Distr Substn Plant	P61	100.00%	40.51%	58.96%	3.93%	55.03%	43.02%	10.60%	1.38%	0.03%	0.53%
15	Line Transformer Plant	P68	100.00%	70.58%	29.06%	5.33%	23.73%	22.49%	1.25%	0.00%	0.00%	0.36%
16	Services Plant	P69	100.00%	90.12%	9.88%	3.00%	6.88%	6.88%	0.00%	0.00%	0.00%	0.00%
17	Dist Plt Overhead Lines	POL	100.00%	63.47%	31.47%	4.39%	27.08%	22.20%	4.88%	0.00%	0.00%	5.06%
18	Real Est & Property Tax	PT0	100.00%	42.67%	56.30%	3.62%	52.68%	39.30%	9.55%	3.62%	0.21%	1.04%
19	Produc, Trans & Distrib	PTD	100.00%	40.08%	59.04%	3.52%	55.52%	41.09%	10.14%	4.07%	0.22%	0.87%
20	Dist Plt Undground Lines	PUL	100.00%	73.72%	25.93%	4.72%	21.21%	17.38%	3.83%	0.00%	0.00%	0.35%
21	Rate Base (Non-Column)	RTBASE	100.00%	41.70%	57.23%	3.57%	53.66%	39.91%	9.78%	3.76%	0.21%	1.07%
22	Stratified Hydro Baseload	STRATH	100.00%	31.30%	68.42%	3.21%	65.21%	47.25%	12.14%	5.57%	0.25%	0.29%
23	Transmission & Distrib	TD	100.00%	52.91%	45.29%	3.99%	41.30%	31.99%	7.23%	1.91%	0.17%	1.80%
24	Labor Dis w/o Sup & Eng	ZDTS	100.00%	57.57%	38.06%	4.64%	33.42%	26.82%	5.78%	0.78%	0.04%	4.37%

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
INTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
25	Labor w/o A&G	LABOR(S)	311,527	121,680	186,758	11,560	175,199	129,352	32,020	13,199	628	3,089
26	Dis O&M w/o Sup, Cust Install & I	OXDTS	89,364	53,374	31,139	4,133	27,007	22,085	4,732	183	8	4,850
27	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	2,350,637	833,027	1,502,874	81,862	1,421,012	1,041,987	261,473	112,187	5,365	14,736
28	Total P51 & P61A	P5161A	125,068	40,449	84,314	4,049	80,265	58,422	14,864	6,667	312	305
29	Produc, Trans & Distrib	PTD	18,976,765	7,606,809	11,204,133	668,691	10,535,442	7,797,969	1,923,695	771,998	41,780	165,823
30	Transmission & Distrib	TD	7,495,640	3,966,022	3,394,638	299,050	3,095,588	2,397,678	541,648	143,394	12,869	134,980
31	Labor Dis w/o Sup & Eng, Cust In	ZDTS	47,220	27,185	17,974	2,193	15,781	12,663	2,731	368	19	2,062

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			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
EXTERNAL ALLOCATORS		Extern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Customers - Ave Monthly	C11	100.00%	87.72%	10.19%	6.55%	3.64%	3.60%	0.04%	0.00%	0.00%	2.08%
2	Cust Acctg Wtg Factor	C11WA	100.00%	83.01%	16.59%	9.30%	7.29%	7.18%	0.10%	0.00%	0.00%	0.40%
3	Mo Cus Wtd By Mtr Invest	C12WM	100.00%	66.40%	33.38%	9.91%	23.47%	22.05%	1.37%	0.04%	0.02%	0.21%
4	Sec & Pri Customers	C61PS	100.00%	89.19%	10.38%	6.67%	3.71%	3.68%	0.04%	0.00%	0.00%	0.43%
5	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	100.00%	95.25%	4.50%	3.86%	0.64%	0.63%	0.01%	0.00%	0.00%	0.24%
6	C62Sec, w/o Ltg & C/I Undergrou	C62NL	100.00%	94.91%	5.09%	3.28%	1.81%	1.81%	0.00%	0.00%	0.00%	0.00%
7	Secondary Customers	C62Sec	100.00%	89.22%	10.35%	6.67%	3.68%	3.68%	0.00%	0.00%	0.00%	0.43%
8	Summer Peak Resp KW	D10S	100.00%	38.45%	61.55%	3.41%	58.14%	43.58%	10.40%	3.93%	0.23%	0.00%
9	Transmission Demand %	D10T	100.00%	35.69%	63.99%	3.35%	60.64%	45.00%	10.75%	4.67%	0.23%	0.32%
10	Winter Peak Resp KW	D10W	100.00%	31.80%	67.43%	3.27%	64.16%	47.00%	11.23%	5.71%	0.22%	0.78%
11	Alternative Production Allocator	1CP	100.00%	38.45%	61.55%	3.41%	58.14%	43.58%	10.40%	3.93%	0.23%	0.00%
12	Sec, Pri & TT, Class Coin kW @ $	D60Sub	100.00%	41.57%	57.88%	4.03%	53.85%	44.02%	9.92%	-0.08%	0.00%	0.55%
13	Sec & Pri, Cl Coin kW (no Min Sys	D61PS	100.00%	36.46%	63.21%	3.37%	59.84%	48.35%	11.50%	0.00%	0.00%	0.32%
14	Pri & Sec Coin kW Served w/ 1 Pl	D61PS1Ph	100.00%	74.32%	25.33%	3.73%	21.60%	15.81%	5.79%	0.00%	0.00%	0.35%
15	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	100.00%	74.46%	25.54%	2.06%	23.47%	23.47%	0.00%	0.00%	0.00%	0.00%
16	Sec, Class Coin kW (w/o Min Sys	D62SecL	100.00%	49.27%	50.47%	3.62%	46.85%	46.85%	0.00%	0.00%	0.00%	0.25%
17	Direct Assign Street Lighting	DASL	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
18	On + Off Sales MWH	E8760	100.00%	29.82%	69.83%	3.16%	66.67%	48.00%	12.50%	5.91%	0.26%	0.34%
19	Street Lighting (Dir Assign)	P73	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
20	MWh Sales Excl CIP Exempt	E99XCIP	100.00%	30.80%	68.74%	3.13%	65.617%	50.17%	11.63%	3.52%	0.29%	0.45%
21	Present Rev	R01	100.00%	37.27%	61.86%	3.52%	58.35%	43.79%	9.98%	4.34%	0.24%	0.87%
22	Late Fee Revenue Allocator	LateFee	100.00%	86.07%	13.84%	5.65%	8.19%	7.75%	0.41%	0.01%	0.02%	0.09%

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
EXTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
23	Customers - B Basis	C10	1,319,164	1,176,546	136,961	87,960	49,001	48,497	479	15	9	5,658
24	Cust - Ave Monthly (C10-Area Lt)	C11	1,345,380	1,180,196	137,160	88,160	49,001	48,497	479	15	9	28,024
25	Mo Cus Wtd By Cus Acct	C11WA	1,421,780	1,180,196	235,927	132,239	103,687	102,106	1,490	58	33	5,658
26	Cust Acctg Wtg Factor	C11WAF	15.26	1.00	14.26	1.50	12.76	2.11	3.11	3.88	3.67	N/A
27	Cust-Ave Mo (C11 w/ Dir Assign $	C12	1,319,887	1,180,196	137,160	88,160	49,001	48,497	479	15	9	2,531
28	Mo Cus Wtd By Mtr Invest	C12WM	169,282,003	112,411,179	56,509,115	16,772,418	39,736,697	37,321,888	2,315,215	62,595	36,999	361,709
29	Meter Invest / Cust Factor	C12WMF	14,311	95	14,073	190	13,883	770	4,829	4,173	4,111	143
30	Sec & Pri Customers	C61PS	1,319,140	1,176,546	136,937	87,960	48,977	48,497	479	0	0	5,658
31	% Served by Primary Single Phase		0.0%	73.59%	0.00%	39.93%	0.00%	11.80%	18.18%	0.00%	0.00%	39.28%
32	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	908,936	865,776	40,938	35,126	5,812	5,725	87	0	0	2,222
33	C62Sec, w/o Ltg & C/I Undergrou	C62NL	1,239,680	1,176,546	63,135	40,696	22,438	22,438	0	0	0	0
34	Secondary Customers	C62Sec	1,318,661	1,176,546	136,458	87,960	48,497	48,497	0	0	0	5,658
35	Summer Peak Resp KW	D10S	25,569	9,831	15,739	873	14,865	11,143	2,660	1,005	58	0
36	Dmd (D10S x Fact + D10W)/1000	D10T	10,000,000	3,568,754	6,398,972	335,441	6,063,530	4,499,780	1,074,569	466,640	22,541	32,274
37	Winter Peak Resp KW	D10W	4,156	1,321	2,802	136	2,666	1,953	467	237	9	32
38	Alternative Production Allocator	1CP	25,569	9,831	15,739	873	14,865	11,143	2,660	1,005	58	0
39	Sec, Pri & TT, Class Coin kW @ $	D60Sub	6,521,671	2,710,931	3,774,971	262,798	3,512,174	2,870,693	646,707	(5,227)	0	35,769
40	Sec & Pri, Class Coin kW (w/o Mi	D61PS	5,864,995	2,138,528	3,707,447	197,629	3,509,818	2,835,455	674,363	0	0	19,020
41	Pri & Sec Coin kW Served w/ 1 Pl	D61PS1Ph	2,117,366	1,573,663	536,232	78,920	457,312	334,700	122,611	0	0	7,471
42	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	10,491,064	7,811,811	2,679,252	216,573	2,462,679	2,462,679	0	0	0	0
43	Sec, Class Coin kW (w/o Min Sys	D62SecL	10,000,000	4,927,402	5,047,295	362,191	4,685,105	4,685,105	0	0	0	25,303
44	Annual Billing kW	D99	49,881.486	0	49,881	0	49,881	38,074	7,940	3,618	250	0
45	Summer Billing kW	D99S	18,305.301	0	18,305	0	18,305	13,907	2,991	1,319	88	0
46	Winter Billing kW	D99W	31,576.184	0	31,576	0	31,576	24,167	4,949	2,299	162	0
47	Non-Coinc Pk Second	DN-Sec	13,621,703	7,811,811	5,790,872	468,096	5,322,776	5,322,776	0	0	0	19,020
48	MWh Sales	E99	28,388,117	8,289,824	19,976,823	841,814	19,135,010	13,576,274	3,661,168	1,819,766	77,801	121,470
49	MWh Sales Excl CIP Exempt	E99XCIP	26,911,724	8,289,824	18,500,430	841,651	17,658,779	13,502,239	3,131,021	947,718	77,801	121,470
50	Late Fee Revenue Allocation	LateFee	100.00%	86.07%	13.84%	5.65%	8.19%	7.75%	0.41%	0.01%	0.02%	0.09%

Northern States Power Company

Docket No. E002/GR-19-564

2022 Class Cost of Service Study Detail ($000)

Rate Base

	Plant In Service	Alloc	1=2+3+10 MN	2 Res	3=4+5 C&I Tot	4 Sm Non-D	5=6 to 9 Demand	6 Second	7 Primary	8 Tr Transf	9 Trans	10 St Ltg
1	Production		11,673,805	3,713,396	7,928,741	373,698	7,555,044	5,458,954	1,396,546	634,192	65,352	31,667
2	Transmission		3,490,183	1,336,133	2,153,737	118,071	2,035,666	1,514,313	362,081	137,523	21,749	313
3	Distribution		4,500,875	2,934,596	1,424,641	200,448	1,224,193	1,005,938	207,980	10,004	271	141,638
4	General		2,035,329	826,363	1,190,996	71,645	1,119,351	825,854	203,545	80,908	9,043	17,970
5	Common		0	0	0	0	0	0	0	0	0	0
6	Total Plant In Service		21,700,191	8,810,488	12,698,115	763,862	11,934,254	8,805,060	2,170,152	862,627	96,415	191,588
7	Production		7,136,281	2,261,334	4,855,241	228,195	4,627,046	3,341,519	855,805	389,660	40,062	19,707
8	Transmission		848,684	325,554	523,087	28,718	494,369	367,662	87,790	33,229	5,689	42
9	Distribution		1,597,559	1,059,382	497,286	72,624	424,663	352,091	68,710	3,747	114	40,890
10	General		1,059,356	430,109	619,895	37,290	582,604	429,844	105,942	42,112	4,707	9,353
11	Common		0	0	0	0	0	0	0	0	0	0
12	Total Depreciation Reserve		10,641,880	4,076,379	6,495,509	366,826	6,128,683	4,491,116	1,118,247	468,748	50,571	69,992
13	**Net Plant In Service**		11,058,311	4,734,109	6,202,607	397,036	5,805,571	4,313,943	1,051,905	393,880	45,843	121,596
14	Deducts: Accum Defer Inc Tax		2,015,705	817,993	1,177,664	71,344	1,106,320	819,587	200,216	77,373	9,144	20,048
15	Constr Work In Progress		507,890	201,906	303,356	17,680	285,676	210,684	52,048	20,686	2,258	2,628
16	Fuel Inventory		65,875	19,719	45,928	2,073	43,854	31,433	8,177	3,859	385	228
17	Materials & Supplies		153,932	52,515	100,752	5,056	95,696	69,484	17,622	7,774	815	665
18	Prepayments		85,979	36,808	48,226	3,087	45,139	33,541	8,179	3,062	356	945
19	Non-Plant & Work Cash		(50,542)	(25,581)	(24,419)	(1,779)	(22,640)	(17,264)	(4,015)	(1,182)	(178)	(542)
20	Total Additions		763,134	285,367	473,842	26,118	447,725	327,878	82,011	34,200	3,637	3,925
21	**Rate Base**		9,805,740	4,201,483	5,498,785	351,810	5,146,976	3,822,234	933,700	350,707	40,335	105,472

Income Statement

		MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
22A	**Tot Oper Rev - Pres**	3,644,178	1,344,927	2,271,022	126,320	2,144,702	1,596,648	369,909	160,836	17,308	28,228
22B	**Tot Oper Rev - Prop**	4,110,282	1,549,639	2,527,287	144,387	2,382,900	1,773,787	412,985	175,467	20,660	33,356
23	Oper & Maint	2,426,359	858,902	1,552,491	83,654	1,468,837	1,072,446	268,953	115,138	12,300	14,966
24	Book Depr + IRS Int	760,859	302,864	449,518	26,537	422,981	311,411	76,984	31,173	3,414	8,477
25	Payroll, Rl Est & Prop Tax	224,526	95,685	126,528	8,119	118,409	87,934	21,407	8,137	930	2,313
26	Deferred Inc Tax & Net ITC	(190,897)	(78,986)	(109,658)	(6,787)	(102,871)	(76,103)	(18,635)	(7,320)	(813)	(2,252)
27A	Present Income Tax	56,478	19,940	35,632	1,930	33,703	32,111	(177)	1,625	144	906
27B	Proposed Income Tax	190,446	78,779	109,288	7,122	102,166	83,024	12,204	5,830	1,108	2,379
28	Allow Funds Dur Const	33,500	13,321	20,017	1,160	18,857	13,913	3,430	1,358	156	162
29A	**Present Return**	400,352	159,843	236,528	14,028	222,500	182,762	24,808	13,440	1,489	3,981
29B	**Proposed Return**	732,489	305,717	419,137	26,902	392,235	308,988	55,504	23,866	3,878	7,635
30A	**Pres Ret on Rt Base**	4.08%	3.80%	4.30%	3.99%	4.32%	4.78%	2.66%	3.83%	3.69%	3.77%
30B	**Prop Ret on Rt Base**	**7.47%**	7.28%	7.62%	7.65%	7.62%	8.08%	5.94%	6.81%	9.61%	7.24%
31A	**Pres Ret on Common**	3.76%	3.23%	4.17%	3.58%	4.22%	5.09%	1.04%	3.28%	3.01%	3.17%
31B	**Prop Ret on Common**	**10.21%**	9.84%	10.50%	10.55%	10.50%	11.38%	7.30%	8.94%	14.29%	9.77%

Northern States Power Company

2022 Class Cost of Service Study Detail ($000)

PRES vs Equal Rev Reqts

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	**UnAdj Equal Rev Reqt @ 7.47%**		**3,533,407**	**1,363,157**	**2,138,062**	**124,527**	**2,013,534**	**1,479,876**	**367,275**	**149,986**	**16,397**	**32,188**
2	**Present Revenue**		**3,068,702**	**1,147,973**	**1,894,005**	**107,401**	**1,786,604**	**1,335,970**	**304,267**	**132,106**	**14,261**	**26,724**
3	**UnAdj Revenue Deficiency**		**464,705**	**215,184**	**244,056**	**17,126**	**226,930**	**143,906**	**63,008**	**17,880**	**2,136**	**5,464**
4	**UnAdj Deficiency / Present**		**15.14%**	**18.74%**	**12.89%**	**15.95%**	**12.70%**	**10.77%**	**20.71%**	**13.53%**	**14.98%**	**20.45%**
			[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS									
5	**Pres Int Rate Discounts**											
6	**Pres Econ Dvlp Rate Discounts**											
7	**Pres Int Rate Disc Cost Alloc**	**D10S**										
8	**Pres Econ Dvlp Disc Cost Alloc**	**R01**										
										HIGHLY CONFIDENTIAL TRADE SECRET ENDS]		
9	**Revenue Requirement Shift**		**0**	**(1,439)**	**1,422**	**1,452**	**(30)**	**10,326**	**(2,136)**	**(6,664)**	**(1,557)**	**17**
10	**Adj Equal Rev Reqt (Rows 1+9)**		**3,533,407**	**1,361,718**	**2,139,484**	**125,980**	**2,013,504**	**1,490,202**	**365,139**	**143,322**	**14,841**	**32,205**
11	**Adj Rev Defic vs Pres Rev (Row 2)**		**464,705**	**213,745**	**245,479**	**18,579**	**226,900**	**154,232**	**60,872**	**11,216**	**580**	**5,481**
12	**Adj Deficiency / Adj Present**		**15.14%**	**18.62%**	**12.96%**	**17.30%**	**12.70%**	**11.54%**	**20.01%**	**8.49%**	**4.06%**	**20.51%**
	Equal Customer Classification											
13	Min Sys & Service Drop		274,928	225,154	26,002	15,170	10,832	10,581	261	(12)	2	23,771
14	Energy Services		54,342	45,267	8,819	4,991	3,827	3,774	50	2	1	257
15	Total Customer **(Cusco)**		329,270	270,421	34,821	20,162	14,659	14,355	311	(10)	3	24,028
16	Ave Monthly Customers		1,355,363	1,189,448	137,784	88,563	49,222	48,719	479	15	9	28,131
17	Svc Drop Reqt	$ / Mo / Cust	$16.90	$15.77	$15.73	$14.27	$18.34	$18.10	$45.39	($67.04)	$20.08	$70.42
18	Ener Svcs Reqt	$ / Mo / Cust	$3.34	$3.17	$5.33	$4.70	$6.48	$6.46	$8.72	$10.43	$9.97	$0.76
19	Total Reqt	$ / Mo / Cust	$20.24	$18.95	$21.06	$18.97	$24.82	$24.55	$54.12	($56.60)	$30.04	$71.18
	Equal Energy Classification											
20	On Peak Rev Reqt		815,092	234,129	579,602	29,814	549,788	400,237	100,997	43,850	4,705	1,360
21	Off Peak Rev Reqt		820,046	254,833	560,785	21,524	539,261	383,338	101,399	49,586	4,938	4,429
22	Total Ener Rev Reqt		1,635,138	488,962	1,140,387	51,338	1,089,049	783,575	202,396	93,436	9,643	5,788
23	Annual MWh Sales		28,303,153.466	8,293,789	19,887,270	834,457	19,052,812	13,451,925	3,625,493	1,798,766	176,628	122,095
24	On Pk Reqt	Mills / kWh	28.799	28.229	29.144	35.729	28.856	29.753	27.858	24.378	26.636	11.136
25	Off Pk Reqt	Mills / kWh	28.974	30.726	28.198	25.794	28.303	28.497	27.968	27.567	27.957	36.273
26	Total Reqt	Mills / kWh	57.772	58.955	57.343	61.523	57.160	58.250	55.826	51.944	54.593	47.409
	Equal Demand Classification											
27	Energy-Related Prod		371,923	114,584	256,187	11,794	244,393	175,868	45,371	21,026	2,129	1,151
28	Capacity-Related Summer Peak Prod		314,088	120,874	193,213	10,653	182,561	136,282	32,530	12,261	1,488	0
29	Capacity-Related Winter Peak Prod		94,930	36,533	58,397	3,220	55,177	41,190	9,832	3,706	450	0
30	Total Capacity-Related Prod		409,018	157,407	251,610	13,872	237,738	177,473	42,361	15,967	1,938	0
31	Total Production		780,941	271,992	507,797	25,666	482,131	353,340	87,732	36,992	4,067	1,151
32	Transmission **(Transco)**		472,886	181,841	291,045	16,023	275,022	205,017	48,911	18,436	2,658	0
33	Primary Dist Subs		95,549	38,987	56,044	3,749	52,295	41,091	10,046	1,132	27	518
34	Prim Dist Lines		188,989	94,409	93,942	6,572	87,370	69,490	17,880	0	0	638
35	Second Dist, Trans		30,633	16,545	14,025	1,018	13,007	13,007	0	0	0	63
36	Total Distribution **(Disco)**		315,172	149,940	164,011	11,339	152,673	123,589	27,926	1,132	27	1,220
37	Total Demand Rev Reqt		1,568,999	603,774	962,854	53,028	909,826	681,946	164,568	56,560	6,752	2,371
38	Annual Billing kW		49,661,671	0	49,661,671	0	49,661,671	37,724,544	7,862,754	3,578,561	495,812	0
39	Base Rev Reqt	$ / kW	$0.00	$0.00	$5.16	$0.00	$4.92	$4.66	$5.77	$5.88	$4.29	$0.00
40	Summer Rev Reqt	$ / kW	$0.00	$0.00	$3.89	$0.00	$3.68	$3.61	$4.14	$3.43	$3.00	$0.00
41	Winter Rev Reqt	$ / kW	$0.00	$0.00	$1.18	$0.00	$1.11	$1.09	$1.25	$1.04	$0.91	$0.00
42	Prod Rev Reqt	$ / kW	$0.00	$0.00	$10.23	$0.00	$9.71	$9.37	$11.16	$10.34	$8.20	$0.00
43	Tran Rev Reqt	$ / kW	$0.00	$0.00	$5.86	$0.00	$5.54	$5.43	$6.22	$5.15	$5.36	$0.00
44	Dist Rev Reqt	$ / kW	$0.00	$0.00	$3.30	$0.00	$3.07	$3.28	$3.55	$0.32	$0.05	$0.00
45	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$19.39	$0.00	$18.32	$18.08	$20.93	$15.81	$13.62	$0.00
46	Tot Dmd Rev Reqt	Mills / kWh	55.435	72.798	48.416	63.548	47.753	50.695	45.392	31.444	38.225	19.423
47	Summer Billing kW		18,171,839	0	18,171,839	0	18,171,839	13,728,851	2,953,825	1,300,914	188,249	0
48	Winter Billing kW		31,489,831	0	31,489,831	0	31,489,831	23,995,693	4,908,929	2,277,647	307,562	0
49	Tot Summer Reqt	$ / kW	$0.00	$0.00	$24.95	$0.00	$23.58	$23.30	$26.56	$20.77	$17.61	$0.00
50	Tot Winter Reqt	$ / kW	$0.00	$0.00	$16.18	$0.00	$15.29	$15.09	$17.55	$12.97	$11.17	$0.00
51	Energy + Production **(Genco)**		2,416,078	760,954	1,648,185	77,004	1,571,181	1,136,915	290,128	130,428	13,709	6,940

Northern States Power Company

2022 Class Cost of Service Study Detail ($000)

PROP vs Equal Rev Reqts

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	**Proposed Ret On Rt Base**		**7.47%**	**7.28%**	**7.62%**	**7.65%**	**7.62%**	**8.08%**	**5.94%**	**6.81%**	**9.61%**	**7.24%**
2	**UnAdj Equalized Rev Reqt**		**3,533,407**	**1,363,157**	**2,138,062**	**124,527**	**2,013,534**	**1,479,876**	**367,275**	**149,986**	**16,397**	**32,188**
3	**Proposed Revenue**		**3,533,407**	**1,351,742**	**2,149,819**	**125,400**	**2,024,419**	**1,512,808**	**347,286**	**146,713**	**17,611**	**31,846**
4	**UnAdj Revenue Deficiency**		**(0)**	**11,415**	**(11,757)**	**(872)**	**(10,885)**	**(32,933)**	**19,989**	**3,272**	**(1,213)**	**342**
5	**UnAdj Deficiency / Proposed**		**0.00%**	**0.84%**	**-0.55%**	**-0.70%**	**-0.54%**	**-2.18%**	**5.76%**	**2%**	**-7%**	**1.07%**
			[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS									
6	**Prop Interrupt Rate Discounts**											
7	**Prop Econ Dev Rate Discounts**											
8	**Prop Int Rate Disc Cost Alloc**	**D10S**										
9	**Prop ED Discount Cost Alloc**	**R01**										
												HIGHLY CONFIDENTIAL TRADE SECRET ENDS]
10	**Revenue Requirement Shift**		**0**	**3,715**	**(3,732)**	**1,693**	**(5,425)**	**7,746**	**(3,962)**	**(7,568)**	**(1,641)**	**17**
11	**Adj Equal Rev (Rows 2+10)**		**3,533,407**	**1,366,872**	**2,134,329**	**126,220**	**2,008,109**	**1,487,621**	**363,313**	**142,418**	**14,756**	**32,205**
12	**Adj Rev Defic vs Prop Rev (Row 3)**		**(0)**	**15,130**	**(15,489)**	**821**	**(16,310)**	**(25,187)**	**16,027**	**(4,295)**	**(2,855)**	**359**
13	**Adj Deficiency / Adj Prop**		**0.00%**	**1.12%**	**-0.72%**	**0.65%**	**-0.81%**	**-1.66%**	**4.61%**	**-2.93%**	**-16.21%**	**1.13%**
	Prop Customer Component											
14	Min Sys & Service Drop		270,277	220,567	26,264	15,219	11,045	10,801	253	(12)	2	23,447
15	Energy Services		54,332	45,257	8,819	4,991	3,828	3,775	50	2	1	257
16	Total Customer **(Cusco)**		324,609	265,823	35,082	20,210	14,872	14,576	304	(10)	3	23,703
17	Ave Monthly Customers		1,355,363	1,189,448	137,784	88,563	49,222	48,719	479	15	9	28,131
18	Svc Drop Reqt	$ / Mo / Cust	$16.62	$15.45	$15.88	$14.32	$18.70	$18.48	$44.09	($67.23)	$20.59	$69.46
19	Ener Svcs Reqt	$ / Mo / Cust	$3.34	$3.17	$5.33	$4.70	$6.48	$6.46	$8.72	$10.43	$9.98	$0.76
20	Total Reqt	$ / Mo / Cust	$19.96	$18.62	$21.22	$19.02	$25.18	$24.93	$52.81	($56.80)	$30.56	$70.22
	Prop Energy Component											
21	On Peak Rev Reqt		814,879	234,030	579,490	29,810	549,679	400,320	100,838	43,810	4,711	1,359
22	Off Peak Rev Reqt		819,815	254,724	560,664	21,521	539,142	383,418	101,238	49,542	4,945	4,427
23	Total Ener Rev Reqt		1,634,694	488,754	1,140,153	51,331	1,088,822	783,738	202,076	93,352	9,657	5,787
24	Annual MWh Sales		28,303,153	8,293,789	19,887,270	834,457	19,052,812	13,451,925	3,625,493	1,798,766	176,628	122,095
25	On Pk Reqt	Mills / kWh	28.791	28.218	29.139	35.724	28.850	29.759	27.813	24.356	26.674	11.133
26	Off Pk Reqt	Mills / kWh	28.965	30.713	28.192	25.791	28.297	28.503	27.924	27.542	27.997	36.261
27	Total Reqt	Mills / kWh	57.757	58.930	57.331	61.515	57.148	58.262	55.737	51.898	54.672	47.394
	Prop Demand Component											
28	Energy-Related Prod		374,849	112,722	260,975	12,156	248,819	190,885	36,095	19,090	2,749	1,151
29	Capacity-Related Summer Peak Prod		315,519	120,538	194,981	10,772	184,209	139,933	30,693	11,969	1,615	0
30	Capacity-Related Winter Peak Prod		95,363	36,432	58,931	3,256	55,676	42,293	9,277	3,618	488	0
31	Total Capacity-Related Prod		410,882	156,970	253,912	14,027	239,885	182,226	39,969	15,587	2,103	0
32	Total Production		785,731	269,692	514,887	26,183	488,704	373,112	76,065	34,676	4,852	1,151
33	Transmission **(Transco)**		475,861	180,650	295,211	16,303	278,908	214,131	44,060	17,647	3,069	0
34	Primary Dist Subs		94,664	38,149	56,003	3,757	52,246	42,266	8,901	1,049	30	511
35	Prim Dist Lines		187,216	92,500	94,084	6,597	87,487	71,607	15,880	0	0	631
36	Second Dist. Trans		30,634	16,174	14,398	1,018	13,380	13,380	0	0	0	62
37	Total Distribution **(Disco)**		312,513	146,823	164,485	11,373	153,113	127,252	24,782	1,049	30	1,205
38	Total Demand Rev Reqt		1,574,105	597,165	974,583	53,859	920,724	714,495	144,907	53,372	7,951	2,356
39	Annual Billing kW		49,661,671	0	49,661,671	0	49,661,671	37,724,544	7,862,754	3,578,561	495,812	0
40	Base Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$5.01	$5.06	$4.59	$5.33	$5.54	$0.00
41	Summer Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$3.71	$3.71	$3.90	$3.34	$3.26	$0.00
42	Winter Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$1.12	$1.12	$1.18	$1.01	$0.98	$0.00
43	Prod Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$9.84	$9.89	$9.67	$9.69	$9.78	$0.00
44	Tran Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$5.62	$5.68	$5.60	$4.93	$6.19	$0.00
45	Dist Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$3.08	$3.37	$3.15	$0.29	$0.06	$0.00
46	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$18.54	$18.94	$18.43	$14.91	$16.04	$0.00
47	Tot Dmd Rev Reqt	Mills / kWh	55.616	72.002	49.005	64.543	48.325	53.115	39.969	29.671	45.016	19.297
48	Summer Billing kW		18,171,839	0	18,171,839	0	18,171,839	13,728,851	2,953,825	1,300,914	188,249	0
49	Winter Billing kW		31,489,831	0	31,489,831	0	31,489,831	23,995,693	4,908,929	2,277,647	307,562	0
50	Tot Summer Reqt	$ / kW	$0.00	$0.00	$25.24	$0.00	$23.85	$24.30	$23.74	$19.76	$20.37	$0.00
51	Tot Winter Reqt	$ / kW	$0.00	$0.00	$16.38	$0.00	$15.48	$15.87	$15.24	$12.15	$13.38	$0.00
52	Energy + Production **(Genco)**		2,420,424	758,446	1,655,040	77,514	1,577,526	1,156,849	278,141	128,028	14,508	6,938
53	Prop Rev - Pres Rev (Pg 2)		464,705	203,769	255,813	17,999	237,814	176,838	43,019	14,608	3,349	5,122
54	Difference / Present		15.14%	17.75%	13.51%	16.76%	13.31%	13.24%	14.14%	11.06%	23.49%	19.17%

2022 Class Cost of Service Study Detail ($000) | Page 4 of 14

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

Original Plant in Service

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Summer Peak	D10S		1,945,856	750,616	1,195,240	66,070	1,129,170	842,970	201,181	75,818	9,201	0
2	WInter Peak	D10S		588,117	226,867	361,250	19,969	341,281	254,780	60,805	22,915	2,781	0
3	Total Peak	D10S		2,533,973	977,483	1,556,490	86,039	1,470,451	1,097,750	261,986	98,733	11,982	0
4	Base Load	E8760		6,505,593	1,947,381	4,535,671	204,751	4,330,920	3,104,238	807,562	381,131	37,988	22,540
5	Nuclear Fuel	E8760		2,634,239	788,532	1,836,580	82,908	1,753,672	1,256,965	326,997	154,327	15,382	9,127
6	Total	28.03%	120, 310-346	11,673,805	3,713,396	7,928,741	373,698	7,555,044	5,458,954	1,396,546	634,192	65,352	31,667
	Transmission												
7	Gen Step Up Base	E8760		90,419	27,066	63,040	2,846	60,194	43,145	11,224	5,297	528	313
8	Gen Step Up Peak	D10S		38,085	14,691	23,393	1,293	22,100	16,499	3,938	1,484	180	0
9	Total Gen Step Up			128,504	41,757	86,433	4,139	82,295	59,644	15,162	6,781	708	313
10	Bulk Transmission	D10S		3,355,467	1,294,376	2,061,092	113,932	1,947,160	1,453,633	346,920	130,741	15,866	0
11	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign		6,211	0	6,211	0	6,211	1,037	0	0	5,174	0
13	Total		350-359	3,490,183	1,336,133	2,153,737	118,071	2,035,666	1,514,313	362,081	137,523	21,749	313
	Distribution:												
	Substations												
14	Generat Step Up	STRATH		3,046	957	2,081	97	1,983	1,431	367	168	17	9
15	Bulk Transmission	D10S		1,829	705	1,123	62	1,061	792	189	71	9	0
16	Distrib Function	D60Sub		726,855	303,941	418,888	29,198	389,690	318,865	71,786	(962)	0	4,026
17	Direct Assign	Dir Assign		18,193.613	0	18,194	0	18,194	410	6,861	10,696	227	0
18	Total		360-363	749,924	305,604	440,285	29,357	410,928	321,498	79,204	9,973	253	4,035
	Overhead Lines												
19	Primary Capacity 1 Phase	D61PS1Ph		178,277	132,748	44,896	6,601	38,295	28,029	10,266	0	0	633
20	Primary Capacity Multi Phase	D61PS		383,575	140,512	241,808	12,876	228,932	184,953	43,979	0	0	1,255
21	Primary Customer 1 Phase	C61PS1Ph		95,637	91,107	4,294	3,684	610	600	9	0	0	236
22	Primary Customer Multi Phase	C61PS		205,770	183,580	21,297	13,681	7,617	7,543	74	0	0	893
23	Total Primary			863,259	547,946	312,295	36,842	275,454	221,125	54,328	0	0	3,017
24	Second Capacity	D62SecL		43,873	21,653	22,108	1,586	20,522	20,522	0	0	0	112
25	Second Customer	C62Sec		157,850	140,878	16,287	10,498	5,788	5,788	0	0	0	685
26	Total Secondary			201,723	162,532	38,395	12,085	26,310	26,310	0	0	0	797
27	Street Lighting	DASL		52,732	0	0	0	0	0	0	0	0	52,732
28	Total		364,365	1,117,714	710,478	350,690	48,926	301,764	247,436	54,328	0	0	56,546
	Underground Lines												
29	Primary Capacity 1 Phase	D61PS1Ph		306,884	228,510	77,284	11,363	65,921	48,249	17,672	0	0	1,090
30	Primary Capacity Multi Phase	D61PS		441,072	161,575	278,054	14,806	263,248	212,677	50,571	0	0	1,443
31	Primary Customer 1 Phase	C61PS1Ph		348,753	332,232	15,659	13,436	2,223	2,190	33	0	0	862
32	Primary Customer Multi Phase	C61PS		501,249	447,195	51,880	33,325	18,555	18,374	181	0	0	2,174
33	Total Primary			1,597,957	1,169,511	422,876	72,930	349,946	281,490	68,457	0	0	5,570
34	Second Capacity	D62SecL		51,408	25,372	25,905	1,859	24,046	24,046	0	0	0	131
35	Second Customer	C62Sec		144,520	128,981	14,911	9,612	5,299	5,299	0	0	0	627
36	Total Secondary			195,928	154,353	40,816	11,470	29,346	29,346	0	0	0	758
37	Street Lighting	DASL		0	0	0	0	0	0	0	0	0	0
38	Total		366,367	1,793,885	1,323,864	463,693	84,400	379,292	310,836	68,457	0	0	6,328
	Line Transformers												
39	Primary	D61PS		42,315	15,501	26,675	1,420	25,255	20,403	4,852	0	0	138
40	Second Capacity	D62SecL		126,328	62,348	63,658	4,567	59,091	59,091	0	0	0	322
41	Second Customer	C62Sec		221,847	197,994	22,890	14,755	8,135	8,135	0	0	0	963
42	Total		368	390,490	275,843	113,224	20,742	92,481	87,629	4,852	0	0	1,423
	Services												
43	Second Capacity	D62NLL		68,335	50,875	17,461	1,412	16,048	16,048	0	0	0	0
44	Second Customer	C62NL		223,503	212,155	11,348	7,315	4,033	4,033	0	0	0	0
43	Total Services	C62NL	369	291,839	263,030	28,808	8,727	20,081	20,081	0	0	0	0
44	Meters	C12WM	370	83,896	55,777	27,941	8,295	19,646	18,458	1,139	31	18	178
45	Street Lighting	Dir Assign	373	73,127	0	0	0	0	0	0	0	0	73,127
46	**Total Distribution**			4,500,875	2,934,596	1,424,641	200,448	1,224,193	1,005,938	207,980	10,004	271	141,638
47	**General & Common Plant**	PTD	303, 389-399	2,035,329	826,363	1,190,996	71,645	1,119,351	825,854	203,545	80,908	9,043	17,970
48	Prelim Elec Plant			21,700,191	8,810,488	12,698,115	763,862	11,934,254	8,805,060	2,170,152	862,627	96,415	191,588
49	TBT Investment	NEPIS		0	0	0	0	0	0	0	0	0	0
50	**Elec Plant in Serv**			21,700,191	8,810,488	12,698,115	763,862	11,934,254	8,805,060	2,170,152	862,627	96,415	191,588

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HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

Accum Deprec; Net Plant

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		1,448,443	558,738	889,704	49,180	840,524	627,484	149,754	56,437	6,849	0
2	Decom Int Peaking	D10S		0	0	0	0	0	0	0	0	0	0
3	Decom Int Baseload	E8760		0	0	0	0	0	0	0	0	0	0
4	Nuclear Fuel	E8760		2,464,907	737,844	1,718,522	77,578	1,640,944	1,176,166	305,978	144,407	14,393	8,540
5	Base Load	E8760		3,222,932	964,751	2,247,014	101,436	2,145,579	1,537,869	400,074	188,816	18,820	11,167
6	Total		108,111,115,120.5	7,136,281	2,261,334	4,855,241	228,195	4,627,046	3,341,519	855,805	389,660	40,062	19,707
	Transmission												
7	Gen Step Up Base	E8760		12,177	3,645	8,490	383	8,106	5,810	1,512	713	71	42
8	Gen Step Up Peak	D10S		15,144	5,842	9,302	514	8,788	6,561	1,566	590	72	0
9	Total Gen Step Up			27,321	9,487	17,792	897	16,895	12,371	3,077	1,303	143	42
10	Bulk Transmission	D10S		819,356	316,067	503,288	27,820	475,468	354,956	84,713	31,925	3,874	0
11	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign		2,006	0	2,006	0	2,006	335	0	0	1,672	0
13	Total		108,111,115,120.5	848,684	325,554	523,087	28,718	494,369	367,662	87,790	33,229	5,689	42
	Distribution												
14	Generat Step Up	STRATH		2,322	729	1,586	74	1,512	1,090	280	128	13	7
15	Bulk Transmission	D10S		687	265	422	23	398	297	71	27	3	0
16	Distrib Function	D60Sub		251,562	105,193	144,975	10,105	134,870	110,358	24,845	(333)	0	1,394
17	Direct Assign	Dir Assign		6,633	0	6,633	0	6,633	149	2,502	3,899	83	0
18	Total Substations			261,203	106,187	153,616	10,203	143,413	111,895	27,697	3,722	99	1,400
19	Overhead Lines	POL		380,147	241,642	119,274	16,640	102,633	84,156	18,478	0	0	19,232
20	Underground	PUL		507,234	374,332	131,112	23,865	107,248	87,891	19,357	0	0	1,789
21	Line Transformers	P68		178,607	126,168	51,787	9,487	42,300	40,081	2,219	0	0	651
22	Services	P69		182,065	164,093	17,972	5,444	12,528	12,528	0	0	0	0
23	Meters	C12WM		70,634	46,960	23,525	6,984	16,541	15,541	959	26	15	150
24	Street Lighting	P73		17,668	0	0	0	0	0	0	0	0	17,668
25	Total		108,111,115,120.5	1,597,559	1,059,382	497,286	72,624	424,663	352,091	68,710	3,747	114	40,890
26	**General & CommonPlant**	PTD	108,111,115,120.5	1,059,356	430,109	619,895	37,290	582,604	429,844	105,942	42,112	4,707	9,353
27	**Total Accum Depr**			10,641,880	4,076,379	6,495,509	366,826	6,128,683	4,491,116	1,118,247	468,748	50,571	69,992
28	**Net Elec Plant**			11,058,311	4,734,109	6,202,607	397,036	5,805,571	4,313,943	1,051,905	393,880	45,843	121,596
29	**Net Plant w/ TBT**			11,058,311	4,734,109	6,202,607	397,036	5,805,571	4,313,943	1,051,905	393,880	45,843	121,596
	Subtractions: Accum Defer Inc Tax												
	Production												
30	Peaking Plant	D10S		262,786	101,370	161,416	8,923	152,494	113,843	27,169	10,239	1,243	0
31	Base Load	E8760		922,212	276,055	642,962	29,025	613,937	440,047	114,477	54,028	5,385	3,195
32	Nuclear Fuel	E8760		(5,980)	(1,790)	(4,169)	(188)	(3,981)	(2,854)	(742)	(350)	(35)	(21)
33	Total		190,281,282,283	1,179,019	375,635	800,209	37,759	762,450	551,036	140,904	63,917	6,593	3,175
	Transmission												
34	Gen Step Up Base	E8760		15,609	4,672	10,883	491	10,391	7,448	1,938	914	91	54
35	Gen Step Up Peak	D10S		4,237	1,635	2,603	144	2,459	1,836	438	165	20	0
36	Total Gen Step Up			19,847	6,307	13,486	635	12,850	9,284	2,376	1,080	111	54
37	Bulk Transmission	D10S		716,137	276,251	439,886	24,316	415,570	310,240	74,041	27,903	3,386	0
38	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
39	Direct Assign	Dir Assign		1,204	0	1,204	0	1,204	201	0	0	1,003	0
40	Total		281,282,283	737,187	282,558	454,576	24,951	429,625	319,725	76,417	28,983	4,500	54
	Distribution												
41	Generat Step Up	STRATH		296	93	203	9	193	139	36	16	2	1
42	Bulk Transmission	D10S		240	92	147	8	139	104	25	9	1	0
43	Distrib Function	D60Sub		108,063	45,188	62,277	4,341	57,936	47,406	10,673	(143)	0	599
44	Direct Assign	Dir Assign		2,163	0	2,163	0	2,163	49	816	1,272	27	0
45	Total Substations			110,762	45,373	64,790	4,359	60,431	47,698	11,549	1,154	30	599
46	Overhead Lines	POL		151,859	96,529	47,647	6,647	40,999	33,618	7,381	0	0	7,683
47	Underground	PUL		231,810	171,073	59,920	10,906	49,013	40,167	8,846	0	0	818
48	Line Transformers	P68		53,788	37,996	15,596	2,857	12,739	12,071	668	0	0	196
49	Services	P69		17,643	15,902	1,742	528	1,214	1,214	0	0	0	0
50	Meters	C12WM		9,990	6,642	3,327	988	2,340	2,198	136	4	2	21
51	Street Lighting	P73		13,205	0	0	0	0	0	0	0	0	13,205
52	Total		281,282,283	589,058	373,515	193,021	26,285	166,736	136,966	28,580	1,158	32	22,522
53	**General & Common Plant**	PTD	281,282,283	135,318	54,940	79,183	4,763	74,420	54,907	13,533	5,379	601	1,195
54	**Total Deferred Tax**			2,640,583	1,086,648	1,526,989	93,758	1,433,231	1,062,633	259,434	99,437	11,726	26,945
55	Net Operating Loss (NOL) Carry F	NEPIS		(654,397)	(280,150)	(367,051)	(23,495)	(343,556)	(255,286)	(62,249)	(23,309)	(2,713)	(7,196)
56	Non-Plant Related	LABOR		29,519	11,495	17,726	1,080	16,646	12,240	3,030	1,244	131	298
57	**Accum Def W/ Adj**			2,015,705	817,993	1,177,664	71,344	1,106,320	819,587	200,216	77,373	9,144	20,048

Northern States Power Company

2022 Class Cost of Service Study Detail ($000)

Additions: CWIP, Etc; Rate Base

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		65,518	25,274	40,244	2,225	38,020	28,383	6,774	2,553	310	0
2	Base Load	E8760		83,328	24,944	58,096	2,623	55,474	39,761	10,344	4,882	487	289
3	Nuclear Fuel	E8760		86,691	25,950	60,441	2,728	57,712	41,366	10,761	5,079	506	300
4	Total		107	235,537	76,167	158,781	7,576	151,205	109,510	27,879	12,513	1,303	589
	Transmission												
5	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10S		0	0	0	0	0	0	0	0	0	0
7	Total Gen Step Up			0	0	0	0	0	0	0	0	0	0
8	Bulk Transmission	D10S		115,059	44,384	70,675	3,907	66,768	49,845	11,896	4,483	544	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
11	Total		107	115,059	44,384	70,675	3,907	66,768	49,845	11,896	4,483	544	0
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub		5,702	2,384	3,286	229	3,057	2,501	563	(8)	0	32
15	Direct Assign	Dir Assign		28	0	28	0	28	1	10	16	0	0
16	Total Substations			5,729	2,384	3,314	229	3,085	2,502	574	9	0	32
17	Overhead Lines	POL		20,874	13,269	6,549	914	5,636	4,621	1,015	0	0	1,056
18	Underground	PUL		37,030	27,328	9,572	1,742	7,829	6,416	1,413	0	0	131
19	Line Transformers	P68		928	656	269	49	220	208	12	0	0	3
20	Services	P69		138	125	14	4	10	10	0	0	0	0
21	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
23	Total		107	64,700	43,761	19,718	2,938	16,779	13,757	3,013	9	0	1,222
24	**General & Common Plant**	PTD	107	92,593	37,594	54,182	3,259	50,923	37,571	9,260	3,681	411	817
25	**Total CWIP**			507,890	201,906	303,356	17,680	285,676	210,684	52,048	20,686	2,258	2,628
26	Fuel Inventory	E8760	151,152	65,875	19,719	45,928	2,073	43,854	31,433	8,177	3,859	385	228
	Materials & Supplies												
27	Production	P10		137,523	43,745	93,404	4,402	89,002	64,309	16,452	7,471	770	373
28	Trans & Distr	TD		16,409	8,770	7,348	654	6,694	5,175	1,171	303	45	291
29	Total		154	153,932	52,515	100,752	5,056	95,696	69,484	17,622	7,774	815	665
	Prepayments												
30	Miscellaneous	NEPIS		85,979	36,808	48,226	3,087	45,139	33,541	8,179	3,062	356	945
31	Fuel	E8760		0	0	0	0	0	0	0	0	0	0
32	Insurance	NEPIS	135,143,184,186,232	0	0	0	0	0	0	0	0	0	0
33	Total		235,252,165	85,979	36,808	48,226	3,087	45,139	33,541	8,179	3,062	356	945
34	Non-Plant Assets & Liab	LABOR	190,283,	90,346	35,181	54,252	3,307	50,945	37,462	9,274	3,808	400	913
35	Working Cash	PT0	calculated	(140,888)	(60,762)	(78,670)	(5,086)	(73,584)	(54,726)	(13,290)	(4,990)	(578)	(1,455)
36	**Total Additions**			763,134	285,367	473,842	26,118	447,725	327,878	82,011	34,200	3,637	3,925
37	**Total Rate Base**			9,805,740	4,201,483	5,498,785	351,810	5,146,976	3,822,234	933,700	350,707	40,335	105,472
38	**Common Rate Base (@ 52.50%)**			5,148,013.7	2,205,778	2,886,862	184,700	2,702,162	2,006,673	490,192	184,121	21,176	55,373

Northern States Power Company

2022 Class Cost of Service Study Detail ($000)

Line	Operating Rev (Cal Month)	Alloc	FERC Accounts	1=2+3+10 MN	2 Res	3=4+5 C&I Tot	4 Sm Non-D	5=6 to 9 Demand	6 Second	7 Primary	8 Tr Transf	9 Trans	10 St Ltg
	Retail Revenue												
1	Present Rate Revenue	R01; (calc)	440, 442,444,445	3,068,702	1,147,973	1,894,005	107,401	1,786,604	1,335,970	304,267	132,106	14,261	26,724
2	Proposed Rate Revenue	PROREV; (calc)		3,533,407	1,351,742	2,149,819	125,400	2,024,419	1,512,808	347,286	146,713	17,611	31,846
3	Equal Rate Revenue			3,533,407	1,363,157	2,138,062	124,527	2,013,534	1,479,876	367,275	149,986	16,397	32,188
	Other Retail Revenue												
4	Interdepartmental	R01; R02	448	736	275	454	26	428	320	73	32	3	6
5	Gross Earnings Tax	R01; R02	408	0	0	0	0	0	0	0	0	0	0
6	CIP Adjustment to Program Costs	E99XCIP	456	0	0	0	0	0	0	0	0	0	0
7	**Tot Other Retail Rev**			736	275	454	26	428	320	73	32	3	6
	Other Operating Revenue												
8	Interchg Prod Capacity	P10	456	441,574	140,463	299,913	14,136	285,777	206,491	52,826	23,989	2,472	1,198
9	Interchg Prod Energy	E8760	456	0	0	0	0	0	0	0	0	0	0
10	Interchg Tr Bulk Supply	D10S	456	(9,963)	(3,843)	(6,120)	(338)	(5,781)	(4,316)	(1,030)	(388)	(47)	0
11	Dist Int Sales; Oth Serv	E8760	412,451,456	630	189	439	20	420	301	78	37	4	2
12	Dist Overhd Line Rent	POL	454	5,006	3,182	1,571	219	1,352	1,108	243	0	0	253
13	Connection Charges	C11	451	1,930	1,694	196	126	70	69	1	0	0	40
14	Sales For Resale	E8760	447	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
15	Joint Op Agree-Other PSCo Rev	D10S	456	0	0	0	0	0	0	0	0	0	0
16	Misc Ancillary Trans Rev	D10S		211,973	81,769	130,204	7,197	123,007	91,830	21,916	8,259	1,002	0
17	MISO	D10S	456	(94,933)	(36,620)	(58,312)	(3,223)	(55,089)	(41,126)	(9,815)	(3,699)	(449)	0
18	Other	D10S	451,456,457	12,835	4,951	7,884	436	7,448	5,560	1,327	500	61	0
19	Late Pay Chg - Pres	R16C; R02		5,687	4,895	787	321	466	441	24	1	1	5
20	**Tot Other Op - Pres**		450	574,740	196,679	376,563	18,894	357,669	260,358	65,569	28,699	3,044	1,498
21	Incr Misc Serv - Prop	R01,		447	167	276	16	260	195	44	19	2	4
22	Incr Inter-Dept'l - Prop	R01; R02		91	34	56	3	53	40	9	4	0	1
23	Incr Late Pay - Prop	(R16C); R02		861	741	119	49	71	67	4	0	0	1
	Tot Incr Other Op			1,400	943	452	68	384	301	57	23	3	5
24	**Tot Other Op - Prop**			576,140	197,622	377,014	18,961	358,053	260,659	65,626	28,722	3,046	1,504
25	**Tot Oper Rev - Pres**			3,644,178	1,344,927	2,271,022	126,320	2,144,702	1,596,648	369,909	160,836	17,308	28,228
26	**Tot Oper Rev - Prop**			4,110,282	1,549,639	2,527,287	144,387	2,382,900	1,773,787	412,985	175,467	20,660	33,356
	Tot Oper Rev - Eql			4,110,282	1,561,054	2,515,530	143,514	2,372,016	1,740,855	432,975	178,739	19,447	33,698
	Operating & Maint (Pg 1 of 2)												
	Production Expen												
27	**Fuel**	E8760	501,518,547	648,552	194,137	452,168	20,412	431,756	309,466	80,507	37,996	3,787	2,247
	Purchased Power												
28	Purchases: Cap Peak	D10S		104,467	40,298	64,169	3,547	60,622	45,256	10,801	4,070	494	0
29	Purchases: Cap Base	D10S		38,875	14,996	23,879	1,320	22,559	16,841	4,019	1,515	184	0
30	Purchases: Demand		555	143,342	55,294	88,047	4,867	83,180	62,097	14,820	5,585	678	0
31	Purchases: Other Energy	E8760	555	288,737	86,430	201,306	9,087	192,218	137,775	35,842	16,916	1,686	1,000
32	Tot Non-Assoc Purch			432,078	141,724	289,353	13,954	275,399	199,872	50,662	22,501	2,364	1,000
33	Interchg Agr Capacity	P10WoN	557	40,363	13,060	27,203	1,298	25,904	18,763	4,776	2,143	223	101
34	Interchg Agr Energy	E8760	557	16,433	4,919	11,457	517	10,940	7,841	2,040	963	96	57
35	Tot Wis Interchg Purch			56,797	17,979	38,660	1,816	36,844	26,604	6,816	3,105	319	158
36	**Tot Purchased Power**			488,875	159,704	328,013	15,770	312,243	226,476	57,478	25,606	2,683	1,158
	Other Production		500,502,505-507 509-514,517-519,520, 523-525,528-532,535, 539,543-546,548-550 552-554,556,557 575.1-575.8										
37	Capacity Related	D10S		95,752	36,936	58,816	3,251	55,564	41,481	9,900	3,731	453	0
38	Energy Related	E8760		352,538	105,529	245,788	11,095	234,693	168,219	43,762	20,654	2,059	1,221
39	Total Other Produc	21.36%		448,290.033	142,465	304,604	14,347	290,257	209,700	53,662	24,384	2,511	1,221
40	**Total Production**			1,585,717	496,306	1,084,784	50,529	1,034,256	745,642	191,646	87,986	8,981	4,627
41	**Transmission Exp**	D10S	560-563, 565-568 570-573	259,023	99,919	159,105	8,795	150,310	112,212	26,780	10,093	1,225	0

Northern States Power Company

2022 Class Cost of Service Study Detail ($000)

Operating & Maint (Pg 2 of 2)

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Distribution Expen	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Supervision & Eng'rg	ZDTS	580,590	6,951	4,004	2,642	322	2,320	1,860	401	54	5	305
2	Load Dispatching	T20D80	581	7,517	3,095	4,389	293	4,097	3,290	749	51	7	33
3	Substations	P61	582,591,592	9,370	3,818	5,501	367	5,134	4,017	990	125	3	50
4	Overhead Lines	POL	583,593	42,847	27,236	13,443	1,876	11,568	9,485	2,083	0	0	2,168
5	Underground Lines	PUL	584, 594	15,816	11,672	4,088	744	3,344	2,740	604	0	0	56
6	Line Transformers	P68	595	1,433	1,012	415	76	339	322	18	0	0	5
7	Meters	C12WM	586,597,598	6,274	4,171	2,090	620	1,469	1,380	85	2	1	13
8	Customer Install'n	OXDTS	587	3,920	2,342	1,365	182	1,184	968	207	8	1	212
9	Street Lighting	Dir Assign	585,596	2,326	0	0	0	0	0	0	0	0	2,326
10	Miscellaneous	OXDTS	588	27,100	16,193	9,438	1,256	8,182	6,695	1,429	54	4	1,469
11	Rents (Pole Attachmts)	POL	589	3,532	2,245	1,108	155	953	782	172	0	0	179
12	**Total Distribution**			127,086	75,789	44,480	5,890	38,590	31,540	6,736	293	21	6,816
13	**Customer Accounting**	C11WA	901-905	43,907	36,511	7,220	4,078	3,142	3,098	41	2	1	177
14	**Sales, Econ Dvlp & Other**	R01	912	(5)	(2)	(3)	(0)	(3)	(2)	(0)	(0)	(0)	(0)
	Admin & General												
15	Salaries	LABOR	920	76,411	29,755	45,884	2,797	43,087	31,684	7,844	3,221	338	773
16	Office Supplies	OXTS	921	51,853	18,353	33,180	1,788	31,393	22,920	5,749	2,461	263	320
17	Admin Transfer Credit	OXTS	922	(42,366)	(14,995)	(27,110)	(1,461)	(25,649)	(18,726)	(4,697)	(2,011)	(215)	(261)
18	Outside Services	LABOR	923	18,894	7,357	11,346	692	10,654	7,834	1,940	796	84	191
19	Property Insurance	NEPIS	924	6,726	2,880	3,773	242	3,531	2,624	640	240	28	74
20	Pensions & Benefits	LABOR	926	79,517	30,964	47,749	2,910	44,838	32,972	8,163	3,352	352	804
21	Injuries & Claims	LABOR	925	12,738	4,960	7,649	466	7,183	5,282	1,308	537	56	129
22	Regulatory Exp	R01; R02	928	5,281	1,975	3,259	185	3,074	2,299	524	227	25	46
23	General Advertising	OXTS	930.1	235	83	150	8	142	104	26	11	1	1
24	Contributions	OXTS		0	0	0	0	0	0	0	0	0	0
25	Misc General Exp	OXTS	929, 930.2	(306)	(108)	(196)	(11)	(185)	(135)	(34)	(15)	(2)	(2)
26	Rents	OXTS	931	50,518	17,880	32,326	1,742	30,584	22,329	5,601	2,398	256	311
27	Maint of General Plant	OXTS	935	802	284	513	28	485	354	89	38	4	5
28	Total			260,301	99,388	158,523	9,385	149,138	109,540	27,151	11,256	1,191	2,391
	Cust Service & Info												
29	Cust Assist Exp - Non-CIP	C11P10	908	2,328	1,392	909	113	796	586	140	63	7	27
30	CIP Total	E99XCIP	908	102,371	31,649	70,256	3,184	67,073	51,050	11,812	3,536	674	466
31	Instructional Advertising	C11P10	909	873	522	341	42	298	220	52	24	2	10
32	Total			105,572	33,563	71,506	3,340	68,167	51,856	12,004	3,623	683	503
33	Amortizations	LABOR		44,757	17,428	26,876	1,638	25,238	18,558	4,594	1,887	198	453
34	**Total O&M Expense**			2,426,359	858,902	1,552,491	83,654	1,468,837	1,072,446	268,953	115,138	12,300	14,966

Northern States Power Company

2022 Class Cost of Service Study Detail ($000)

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Book Depreciation												
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		109,606	42,281	67,325	3,722	63,604	47,483	11,332	4,271	518	0
2	Base Load	E8760		318,036	95,201	221,733	10,010	211,724	151,756	39,479	18,632	1,857	1,102
3	Total		403,413	427,642	137,482	289,059	13,731	275,328	199,238	50,811	22,903	2,375	1,102
	Transmission												
4	Gen Step Up Base	E8760		1,638	490	1,142	52	1,091	782	203	96	10	6
5	Gen Step Up Peak	D10S		950	366	583	32	551	411	98	37	4	0
6	Total Gen Step Up			2,588	857	1,725	84	1,642	1,193	302	133	14	6
7	Bulk Transmission	D10S		69,952	26,984	42,968	2,375	40,593	30,304	7,232	2,726	331	0
8	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
9	Direct Assign	Dir Assign		129	0	129	0	129	22	0	0	107	0
10	Total		403,413	72,668	27,841	44,822	2,459	42,363	31,519	7,534	2,859	452	6
	Distribution												
11	Generat Step Up	STRATH		68	22	47	2	45	32	8	4	0	0
12	Bulk Transmission	D10S		42	16	26	1	24	18	4	2	0	0
13	Distrib Function	D60Sub		16,464	6,885	9,488	661	8,827	7,223	1,626	(22)	0	91
14	Direct Assign	Dir Assign		403	0	403	0	403	9	152	237	5	0
15	Total Substations		403,413	16,978	6,922	9,964	665	9,299	7,282	1,791	221	6	91
16	Overhead Lines	POL		38,976	24,775	12,229	1,706	10,523	8,628	1,894	0	0	1,972
17	Underground	PUL		44,870	33,114	11,598	2,111	9,487	7,775	1,712	0	0	158
18	Line Transformers	P68		10,854	7,667	3,147	577	2,570	2,436	135	0	0	40
19	Services	P69		10,574	9,530	1,044	316	728	728	0	0	0	0
20	Meters	C12WM		3,810	2,533	1,269	377	892	838	52	1	1	8
21	Street Lighting	P73		3,947	0	0	0	0	0	0	0	0	3,947
22	Total		403,413	130,010	84,542	39,251	5,752	33,499	27,687	5,584	222	6	6,217
23	**General & Common Plant**	PTD	403,413	130,538	53,000	76,386	4,595	71,791	52,967	13,055	5,189	580	1,153
24	**Total Book Deprec**		403,404	760,859	302,864	449,518	26,537	422,981	311,411	76,984	31,173	3,414	8,477
	Real Estate & Property Tax												
	Production												
25	Peaking Plant	D10S		27,235	10,506	16,729	925	15,804	11,799	2,816	1,061	129	0
26	Base Load	E8760		69,922	20,930	48,749	2,201	46,549	33,364	8,680	4,096	408	242
27	Total		408.1	97,157	31,436	65,479	3,125	62,353	45,163	11,496	5,158	537	242
	Transmission												
28	Gen Step Up Base	E8760		1,115.6734	334	778	35	743	532	138	65	7	4
29	Gen Step Up Peak	D10S		469.9201	181	289	16	273	204	49	18	2	0
30	Total Gen Step Up			1,585.5936	515	1,066	51	1,015	736	187	84	9	4
31	Bulk Transmission	D10S		41,402.6416	15,971	25,432	1,406	24,026	17,936	4,281	1,613	196	0
32	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
33	Direct Assign	Dir Assign		77	0	77	0	77	13	0	0	64	0
34	Total		408.1	43,064.877	16,486	26,575	1,457	25,118	18,685	4,468	1,697	268	4
	Distribution												
35	Generat Step Up	STRATH		38	12	26	1	25	18	5	2	0	0
36	Bulk Transmission	D10S		23	9	14	1	13	10	2	1	0	0
37	Distrib Function	D60Sub		9,184	3,840	5,293	369	4,924	4,029	907	(12)	0	51
38	Direct Assign	Dir Assign		230	0	230	0	230	5	87	135	3	0
39	Total Substations			9,475	3,861	5,563	371	5,192	4,062	1,001	126	3	51
40	Overhead Lines	POL		14,122	8,977	4,431	618	3,813	3,126	686	0	0	714
41	Underground	PUL		22,666	16,727	5,859	1,066	4,792	3,927	865	0	0	80
42	Line Transformers	P68		4,934	3,485	1,431	262	1,169	1,107	61	0	0	18
43	Services	P69		3,687	3,323	364	110	254	254	0	0	0	0
44	Meters	C12WM		1,060	705	353	105	248	233	14	0	0	2
45	Street Lighting	P73		924	0	0	0	0	0	0	0	0	924
46	Total		408.1	56,869	37,079	18,000	2,533	15,468	12,710	2,628	126	3	1,790
47	**General & Common Plant**	PTD	408.1	0	0	0	0	0	0	0	0	0	0
48	**Tot Rl Est & Pr Tax**			197,091	85,002	110,054	7,115	102,939	76,558	18,591	6,981	809	2,036
49	Gross Earnings Tax	R01; R02		0	0	0	0	0	0	0	0	0	0
50	Payroll Taxes	LABOR		27,435	10,683	16,475	1,004	15,470	11,376	2,816	1,156	122	277
51	**Tot Non-Inc Taxes**			224,526	95,685	126,528	8,119	118,409	87,934	21,407	8,137	930	2,313

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

Northern States Power Company Docket No. E002/GR-19-564

2022 Class Cost of Service Study Detail ($000)

Provision For Defer Inc Tax

Line	Production	Alloc	FERC Accounts	1=2+3+10 MN	2 Res	3=4+5 C&I Tot	4 Sm Non-D	5=6 to 9 Demand	6 Second	7 Primary	8 Tr Transf	9 Trans	10 St Ltg
1	Peaking Plant	D10S		(7,850)	(3,028)	(4,822)	(267)	(4,555)	(3,401)	(812)	(306)	(37)	0
2	Nuclear Fuel	E8760		(2,604)	(779)	(1,815)	(82)	(1,733)	(1,242)	(323)	(153)	(15)	(9)
3	Base Load	E8760		(23,809)	(7,127)	(16,600)	(749)	(15,850)	(11,361)	(2,956)	(1,395)	(139)	(82)
4	Total		410, 411	(34,263)	(10,934)	(23,237)	(1,098)	(22,139)	(16,004)	(4,090)	(1,853)	(191)	(92)
	Transmission												
5	Gen Step Up Base	E8760		587	176	409	18	391	280	73	34	3	2
6	Gen Step Up Peak	D10S		224	86	137	8	130	97	23	9	1	0
7	Total Gen Step Up			811	262	547	26	521	377	96	43	4	2
8	Bulk Transmission	D10S		7,252	2,797	4,454	246	4,208	3,142	750	283	34	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		12	0	12	0	12	2	0	0	10	0
11	Total		410, 411	8,075	3,059	5,014	272	4,741	3,521	846	326	49	2
	Distribution												
12	Generat Step Up	STRATH		(27)	(9)	(19)	(1)	(18)	(13)	(3)	(2)	(0)	(0)
13	Bulk Transmission	D10S		(8)	(3)	(5)	(0)	(5)	(3)	(1)	(0)	(0)	0
14	Distrib Function	D60Sub		(409)	(171)	(236)	(16)	(219)	(179)	(40)	1	0	(2)
15	Direct Assign	Dir Assign		(39)	0	(39)	0	(39)	(1)	(15)	(23)	(0)	0
16	Total Substations			(483)	(183)	(298)	(18)	(281)	(197)	(59)	(24)	(1)	(2)
17	Overhead Lines	POL		2,340	1,487	734	102	632	518	114	0	0	118
18	Underground	PUL		(646)	(476)	(167)	(30)	(136)	(112)	(25)	0	0	(2)
19	Line Transformers	P68		(2,655)	(1,876)	(770)	(141)	(629)	(596)	(33)	0	0	(10)
20	Services	P69		(720)	(649)	(71)	(22)	(50)	(50)	0	0	0	0
21	Meters	C12WM		(596)	(396)	(199)	(59)	(140)	(131)	(8)	(0)	(0)	(1)
22	Street Lighting	P73		(493)	0	0	0	0	0	0	0	0	(493)
23	Total		410, 411	(3,253)	(2,093)	(770)	(167)	(603)	(567)	(11)	(24)	(1)	(390)
24	**General & Common Plant**	PTD	410, 411	(2,040)	(828)	(1,194)	(72)	(1,122)	(828)	(204)	(81)	(9)	(18)
25	**Net Operating Loss (NOL) Carry**	NEPIS		(157,543)	(67,445)	(88,366)	(5,656)	(82,709)	(61,459)	(14,986)	(5,611)	(653)	(1,732)
26	**Non - Plant Related**	LABOR	410, 411	(651)	(253)	(391)	(24)	(367)	(270)	(67)	(27)	(3)	(7)
27	**Tot Prov For Defer**			(189,674)	(78,494)	(108,944)	(6,745)	(102,199)	(75,607)	(18,513)	(7,272)	(808)	(2,237)

Inv Tax Credit; Total Oper Exp

Line	Production	Alloc	FERC Accounts	MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
28	Peaking Plant	D10S		(260)	(100)	(160)	(9)	(151)	(113)	(27)	(10)	(1)	0
29	Base Load	E8760		(538)	(161)	(375)	(17)	(358)	(257)	(67)	(32)	(3)	(2)
30	Total		411	(798)	(261)	(535)	(26)	(509)	(369)	(94)	(42)	(4)	(2)
	Transmission												
31	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
32	Gen Step Up Peak	D10S		0	0	0	0	0	0	0	0	0	0
33	Total Gen Step Up			0	0	0	0	0	0	0	0	0	0
34	Bulk Transmission	D10S		(150)	(58)	(92)	(5)	(87)	(65)	(16)	(6)	(1)	0
35	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
36	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
37	Total		411	(150)	(58)	(92)	(5)	(87)	(65)	(16)	(6)	(1)	0
	Distribution												
38	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
39	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
40	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
41	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
42	Total Substations			0	0	0	0	0	0	0	0	0	0
43	Overhead Lines	POL		(267)	(170)	(84)	(12)	(72)	(59)	(13)	0	0	(14)
44	Underground	PUL		0	0	0	0	0	0	0	0	0	0
45	Line Transformers	P68		0	0	0	0	0	0	0	0	0	0
46	Services	P69		0	0	0	0	0	0	0	0	0	0
47	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
48	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
49	Total		411	(267)	(170)	(84)	(12)	(72)	(59)	(13)	0	0	(14)
50	**General & Common Plant**	PTD	411	(7)	(3)	(4)	(0)	(4)	(3)	(1)	(0)	(0)	(0)
51	**Net Inv Tax Credit**			(1,222)	(492)	(715)	(43)	(672)	(496)	(123)	(48)	(5)	(15)
28	TBT Misc Net Exp	NEPIS		0	0	0	0	0	0	0	0	0	0
52	**Total Operating Exp**			**3,220,847**	**1,178,465**	**2,018,879**	**111,522**	**1,907,357**	**1,395,688**	**348,708**	**147,129**	**15,831**	**23,504**
53A	**Pres Op Inc Before Inc Tax**			**423,330**	**166,463**	**252,143**	**14,798**	**237,345**	**200,960**	**21,201**	**13,708**	**1,477**	**4,725**
53B	**Prop Op Inc Before Inc Tax**			**889,435**	**371,175**	**508,408**	**32,864**	**475,544**	**378,099**	**64,277**	**28,338**	**4,829**	**9,852**

2022 Class Cost of Service Study Detail ($000) Page 11 of 14

Tax Deprec; Inc Tax & Return

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		102,374	39,491	62,883	3,476	59,407	44,350	10,584	3,989	484	0
2	Nuclear Fuel	E8760		95,708	28,649	66,727	3,012	63,715	45,668	11,881	5,607	559	332
3	Base Load	E8760		318,090	95,217	221,771	10,011	211,760	151,781	39,486	18,635	1,857	1,102
4	Total		tax books	516,172	163,357	351,381	16,500	334,882	241,800	61,951	28,231	2,900	1,434
	Transmission												
5	Gen Step Up Base	E8760		4,008	1,200	2,795	126	2,668	1,913	498	235	23	14
6	Gen Step Up Peak	D10S		1,607	620	987	55	933	696	166	63	8	0
7	Total Gen Step Up			5,615	1,820	3,782	181	3,601	2,609	664	297	31	14
8	Bulk Transmission	D10S		105,255	40,602	64,653	3,574	61,079	45,598	10,882	4,101	498	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		190	0	190	0	190	32	0	0	158	0
11	Total		tax books	111,060	42,422	68,624	3,755	64,870	48,239	11,546	4,399	687	14
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		14	5	9	0	8	6	1	1	0	0
14	Distrib Function	D60Sub		17,370	7,263	10,010	698	9,313	7,620	1,716	(23)	0	96
15	Direct Assign	Dir Assign		339	0	339	0	339	8	128	199	4	0
16	Total Substations			17,722	7,269	10,357	698	9,659	7,634	1,845	177	4	96
17	Overhead Lines	POL		46,095	29,301	14,463	2,018	12,445	10,204	2,241	0	0	2,332
18	Underground	PUL		51,841	38,258	13,400	2,439	10,961	8,983	1,978	0	0	183
19	Line Transformers	P68		7,515	5,309	2,179	399	1,780	1,686	93	0	0	27
20	Services	P69		8,618	7,767	851	258	593	593	0	0	0	0
21	Meters	C12WM		1,946	1,294	648	192	456	428	26	1	0	4
22	Street Lighting	P73		2,776	0	0	0	0	0	0	0	0	2,776
23	Total		tax books	136,513	89,197	41,898	6,004	35,894	29,528	6,183	177	5	5,418
24	**General & Common Plant**	PTD	tax books	151,748	61,611	88,797	5,342	83,456	61,573	15,176	6,032	674	1,340
25	Net Operating Loss (NOL) Carry F	NEPIS		0	0	0	0	0	0	0	0	0	0
26	**Total Tax Deprec**			915,494	356,588	550,701	31,600	519,101	381,140	94,856	38,840	4,266	8,206
27	Interest Expense		427,431	206,901.12	88,651	116,024	7,423	108,601	80,649	19,701	7,400	851	2,225
28	Other Tax Timing Differ	LABOR		(12,176)	(4,741)	(7,312)	(446)	(6,866)	(5,049)	(1,250)	(513)	(54)	(123)
29	Meals & Enter	LABOR		584	227	350	21	329	242	60	25	3	6
30	Total Tax Deductions			1,110,803	440,725	659,764	38,599	621,165	456,982	113,367	45,751	5,066	10,314
	Inc Tax Additions												
31	Book Depreciation			760,859	302,864	449,518	26,537	422,981	311,411	76,984	31,173	3,414	8,477
32	Deferred Inc Tax & ITC			(190,896.73)	(78,986)	(109,658)	(6,787)	(102,871)	(76,103)	(18,635)	(7,320)	(813)	(2,252)
33	Nuclear Fuel Book Burn	E8760		107,318	32,125	74,822	3,378	71,444	51,208	13,322	6,287	627	372
34	Tax Capitalized Leases	PTD		41,215	16,734	24,117	1,451	22,667	16,723	4,122	1,638	183	364
35	Avoided Tax Interest	RTBASE		20,828	8,924	11,680	747	10,932	8,119	1,983	745	86	224
36	Total Tax Additions			739,323	281,660	450,478	25,325	425,153	311,359	77,775	32,523	3,496	7,184
37	**Total Inc Tax Adjustments**			(371,480)	(159,064)	(209,286)	(13,274)	(196,012)	(145,624)	(35,592)	(13,227)	(1,569)	(3,130)
38A	**Pres Taxable Net Income**			51,850	7,398	42,857	1,524	41,333	55,336	(14,391)	480	(92)	1,595
38B	**Prop Taxable Net Income**			517,955	212,110	299,122	19,590	279,532	232,476	28,685	15,111	3,260	6,723
39A	Pres Fed & State Inc Tax			56,478	19,940	35,632	1,930	33,703	32,111	(177)	1,625	144	906
39B	Prop Fed & State Inc Tax			190,446	78,779	109,288	7,122	102,166	83,024	12,204	5,830	1,108	2,379
40A	Pres Preliminary Return	(total); BASE		366,852	146,522	216,511	12,868	203,643	168,849	21,378	12,083	1,333	3,819
40B	Prop Preliminary Return	(total); BASE		698,989	292,396	399,120	25,742	373,378	295,075	52,073	22,508	3,721	7,473
41	Total AFUDC			33,500	13,321	20,017	1,160	18,857	13,913	3,430	1,358	156	162
42A	**Present Total Return**			400,352	159,843	236,528	14,028	222,500	182,762	24,808	13,440	1,489	3,981
42B	**Proposed Total Return**			732,489	305,717	419,137	26,902	392,235	308,988	55,504	23,866	3,878	7,635
43A	**Pres % Return on Rate Base**			4.08%	3.80%	4.30%	3.99%	4.32%	4.78%	2.66%	3.83%	3.69%	3.77%
43B	**Prop % Return on Rate Base**			7.47%	7.28%	7.62%	7.65%	7.62%	8.08%	5.94%	6.81%	9.61%	7.24%
44A	**Present Common Return**			193,451	71,192	120,503	6,605	113,898	102,113	5,107	6,040	638	1,756
44B	**Proposed Common Return**			525,588	217,066	303,113	19,479	283,634	228,339	35,802	16,466	3,027	5,410
45A	**Pres % Ret on Common Rt Base**			3.76%	3.23%	4.17%	3.58%	4.22%	5.09%	1.04%	3.28%	3.01%	3.17%
45B	**Prop % Ret on Common Rt Base**			10.21%	9.84%	10.50%	10.55%	10.50%	11.38%	7.30%	8.94%	14.29%	9.77%

2022 Class Cost of Service Study Detail ($000) Page 12 of 14

Allow For Funds Used During Constr

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		4,187	1,615	2,572	142	2,430	1,814	433	163	20	0
2	Nuclear Fuel	E8760		4,647	1,391	3,240	146	3,093	2,217	577	272	27	16
3	Base Load	E8760		6,095	1,824	4,249	192	4,058	2,908	757	357	36	21
4	Total		419.1,432	14,929	4,831	10,061	480	9,581	6,939	1,766	792	83	37
	Transmission												
5	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10S		0	0	0	0	0	0	0	0	0	0
7	Total Gen Step Up			0	0	0	0	0	0	0	0	0	0
8	Bulk Transmission	D10S		8,297	3,201	5,096	282	4,815	3,594	858	323	39	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		9	0	9	0	9	2	0	0	8	0
11	Total		419.1,432	8,306	3,201	5,106	282	4,824	3,596	858	323	47	0
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub		586	245	338	24	314	257	58	(1)	0	3
15	Direct Assign	Dir Assign		1	0	1	0	1	0	0	1	0	0
16	Total Substations			587	245	339	24	315	257	58	(0)	0	3
17	Overhead Lines	POL		1,197	761	376	52	323	265	58	0	0	61
18	Underground	PUL		2,108	1,556	545	99	446	365	80	0	0	7
19	Line Transformers	P68		0	0	0	0	0	0	0	0	0	0
20	Services	P69		284	256	28	8	20	20	0	0	0	0
21	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
23	Total		419.1,432	4,177	2,818	1,288	184	1,104	907	197	(0)	0	71
24	**General & Common Plant**	PTD	419.1,432	6,089	2,472	3,563	214	3,348	2,471	609	242	27	54
25	**Total AFUDC**			33,500	13,321	20,017	1,160	18,857	13,913	3,430	1,358	156	162

Labor Allocator

				MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
	Production												
26	Other Prod - Cap	D10S		61,563	23,748	37,815	2,090	35,725	26,670	6,365	2,399	291	0
27	Other Prod - Ene	E8760		158,053	47,312	110,194	4,974	105,219	75,417	19,620	9,260	923	548
28	Total		500 through 557	219,616	71,059	148,009	7,065	140,944	102,087	25,985	11,658	1,214	548
	Transmission												
29	Stepup Subtrans	P5161A		807	262	543	26	517	375	95	43	4	2
30	Bulk Power Subs	D10S		21,081	8,132	12,949	716	12,233	9,133	2,180	821	100	0
31	Total		560 through 571	21,888	8,394	13,492	742	12,750	9,507	2,275	864	104	2
	Distribution												
32	Superv & Eng	ZDTS	580, 590	6,043	3,481	2,297	280	2,017	1,617	348	47	5	265
33	Load Dispatch	D10S	581	6,927	2,672	4,255	235	4,019	3,001	716	270	33	0
34	Substation	P61	582, 592	6,174	2,516	3,625	242	3,383	2,647	652	82	2	33
35	Overhead Lines	POL	583, 593	10,967	6,971	3,441	480	2,961	2,428	533	0	0	555
36	Underground Lines	PUL	584, 594	10,285	7,590	2,659	484	2,175	1,782	393	0	0	36
37	Line Transformer	P68	595	1,218	860	353	65	288	273	15	0	0	4
38	Meter	C12WM	586, 597	3,648	2,425	1,215	361	854	803	50	1	1	8
39	Cust Installation	ZDTS	587	3,585	2,065	1,363	166	1,196	959	207	28	3	157
40	Street Lighting	P73	585, 596	1,050	0	0	0	0	0	0	0	0	1,050
41	Miscellaneous	OXDTS	588	7,608	4,546	2,649	353	2,297	1,880	401	15	1	412
42	Total			57,505	33,128	21,856	2,665	19,191	15,390	3,315	443	44	2,521
43	**Cust Accounting**	C11WA	901,902,903,904,905	8,129	6,760	1,337	755	582	574	8	0	0	33
44	**Sales Expense**	C11P10	912	0	0	0	0	0	0	0	0	0	0
45	**Admin & General**	LABOR	920,921,922,923,924,	156,977	61,127	94,263	5,746	88,517	65,091	16,114	6,617	695	1,587
46	**Service & Inform**	C11P10	908, 909	1,243	743	485	60	425	313	75	34	3	15
47	**Labor**			465,357	181,211	279,441	17,032	262,409	192,961	47,770	19,616	2,061	4,705

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PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	
INTERNAL ALLOCATORS		Intern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	50% Cus, 50% Prod Plt	C11P10	100.00%	59.78%	39.04%	4.87%	34.17%	25.18%	6.00%	2.72%	0.28%	1.17%
2	Peaking Plant Capacity	D10S	100.00%	38.58%	61.42%	3.40%	58.03%	43.32%	10.34%	3.90%	0.47%	0.00%
3	57% Dmd; 43% Energy: Sales & I	D57E43	100.00%	29.93%	69.72%	3.15%	66.57%	47.72%	12.41%	5.86%	0.58%	0.35%
4	40% Dmd; 60% Energy: CIP	D40E60	100.00%	29.93%	69.72%	3.15%	66.57%	47.72%	12.41%	5.86%	0.58%	0.35%
5	20%D10T; 80%D60Sub	T20D80	100.00%	41.17%	58.39%	3.89%	54.50%	43.76%	9.97%	0.67%	0.09%	0.44%
6	Labor w/o (or w/) A&G	LABOR	100.00%	38.94%	60.05%	3.66%	56.39%	41.47%	10.27%	4.22%	0.44%	1.01%
7	Net Plant In Service	NEPIS	100.00%	42.81%	56.09%	3.59%	52.50%	39.01%	9.51%	3.56%	0.41%	1.10%
8	Dis O&M w/o Sup & Misc	OXDTS	100.00%	59.75%	34.83%	4.63%	30.19%	24.71%	5.27%	0.20%	0.01%	5.42%
9	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	100.00%	35.39%	63.99%	3.45%	60.54%	44.20%	11.09%	4.75%	0.51%	0.62%
10	Production Plant	P10	100.00%	31.81%	67.92%	3.20%	64.72%	46.76%	11.96%	5.43%	0.56%	0.27%
11	Production Plant Wo Nuclear	P10WoN	100.00%	32.36%	67.39%	3.22%	64.18%	46.48%	11.83%	5.31%	0.55%	0.25%
12	Total P51 & P61A	P5161A	100.00%	32.47%	67.29%	3.22%	64.07%	46.43%	11.80%	5.28%	0.55%	0.24%
13	Distribution Plant	P60	100.00%	65.20%	31.65%	4.45%	27.20%	22.35%	4.62%	0.22%	0.01%	3.15%
14	Distr Substn Plant	P61	100.00%	40.75%	58.71%	3.91%	54.80%	42.87%	10.56%	1.33%	0.03%	0.54%
15	Line Transformer Plant	P68	100.00%	70.64%	29.00%	5.31%	23.68%	22.44%	1.24%	0.00%	0.00%	0.36%
16	Services Plant	P69	100.00%	90.13%	9.87%	2.99%	6.88%	6.88%	0.00%	0.00%	0.00%	0.00%
17	Dist Plt Overhead Lines	POL	100.00%	63.57%	31.38%	4.38%	27.00%	22.14%	4.86%	0.00%	0.00%	5.06%
18	Real Est & Property Tax	PT0	100.00%	43.13%	55.84%	3.61%	52.23%	38.84%	9.43%	3.54%	0.41%	1.03%
19	Produc, Trans & Distrib	PTD	100.00%	40.60%	58.52%	3.52%	55.00%	40.58%	10.00%	3.98%	0.44%	0.88%
20	Dist Plt Undground Lines	PUL	100.00%	73.80%	25.85%	4.70%	21.14%	17.33%	3.82%	0.00%	0.00%	0.35%
21	Rate Base (Non-Column)	RTBASE	100.00%	42.85%	56.08%	3.59%	52.49%	38.98%	9.52%	3.58%	0.41%	1.08%
22	Stratified Hydro Baseload	STRATH	100.00%	31.41%	68.30%	3.19%	65.11%	46.97%	12.06%	5.52%	0.56%	0.29%
23	Transmission & Distrib	TD	100.00%	53.44%	44.78%	3.99%	40.79%	31.54%	7.13%	1.85%	0.28%	1.78%
24	Labor Dis w/o Sup & Eng	ZDTS	100.00%	57.61%	38.01%	4.63%	33.37%	26.76%	5.76%	0.77%	0.08%	4.38%

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
INTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
25	Labor w/o A&G	LABOR(S)	308,380	120,084	185,178	11,287	173,891	127,870	31,656	12,999	1,366	3,118
26	Dis O&M w/o Sup, Cust Install & M	OXDTS	89,114	53,249	31,035	4,130	26,905	22,016	4,700	178	12	4,830
27	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	2,360,344	835,430	1,510,368	81,375	1,428,993	1,043,301	261,696	112,028	11,968	14,546
28	Total P51 & P61A	P5161A	131,550	42,714	88,514	4,236	84,278	61,074	15,529	6,949	725	322
29	Produc, Trans & Distrib	PTD	19,664,862	7,984,125	11,507,120	692,217	10,814,903	7,979,206	1,966,607	781,719	87,372	173,618
30	Transmission & Distrib	TD	7,991,058	4,270,729	3,578,378	318,519	3,259,859	2,520,252	570,061	147,527	22,020	141,951
31	Labor Dis w/o Sup & Eng, Cust In:	ZDTS	47,876	27,581	18,196	2,219	15,977	12,813	2,760	368	37	2,099

2022 Class Cost of Service Study Detail ($000)

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
EXTERNAL ALLOCATORS		Extern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Customers - Ave Monthly	C11	100.00%	87.76%	10.17%	6.53%	3.63%	3.59%	0.04%	0.00%	0.00%	2.08%
2	Cust Acctg Wtg Factor	C11WA	100.00%	83.15%	16.44%	9.29%	7.16%	7.06%	0.09%	0.00%	0.00%	0.40%
3	Mo Cus Wtd By Mtr Invest	C12WM	100.00%	66.48%	33.30%	9.89%	23.42%	22.00%	1.36%	0.04%	0.02%	0.21%
4	Sec & Pri Customers	C61PS	100.00%	89.22%	10.35%	6.65%	3.70%	3.67%	0.04%	0.00%	0.00%	0.43%
5	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	100.00%	95.26%	4.49%	3.85%	0.64%	0.63%	0.01%	0.00%	0.00%	0.25%
6	C62Sec, w/o Ltg & C/I Undergrou	C62NL	100.00%	94.92%	5.08%	3.27%	1.80%	1.80%	0.00%	0.00%	0.00%	0.00%
7	Secondary Customers	C62Sec	100.00%	89.25%	10.32%	6.65%	3.67%	3.67%	0.00%	0.00%	0.00%	0.43%
8	Summer Peak Resp KW	D10S	100.00%	38.58%	61.42%	3.40%	58.03%	43.32%	10.34%	3.90%	0.47%	0.00%
9	Transmission Demand %	D10T	100.00%	35.82%	63.86%	3.34%	60.52%	44.74%	10.68%	4.63%	0.48%	0.33%
10	Winter Peak Resp KW	D10W	100.00%	31.93%	67.29%	3.25%	64.04%	46.73%	11.16%	5.66%	0.49%	0.78%
11	Alternative Production Allocator	1CP	100.00%	38.58%	61.42%	3.40%	58.03%	43.32%	10.34%	3.90%	0.47%	0.00%
12	Sec, Pri & TT, Class Coin kW @ S	D60Sub	100.00%	41.82%	57.63%	4.02%	53.61%	43.87%	9.88%	-0.13%	0.00%	0.55%
13	Sec & Pri, Cl Coin kW (no Min Sys	D61PS	100.00%	36.63%	63.04%	3.36%	59.68%	48.22%	11.47%	0.00%	0.00%	0.33%
14	Pri & Sec Coin kW Served w/ 1 Pl	D61PS1Ph	100.00%	74.46%	25.18%	3.70%	21.48%	15.72%	5.76%	0.00%	0.00%	0.36%
15	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	100.00%	74.45%	25.55%	2.07%	23.48%	23.48%	0.00%	0.00%	0.00%	0.00%
16	Sec, Class Coin kW (w/o Min Sys	D62SecL	100.00%	49.35%	50.39%	3.62%	46.78%	46.78%	0.00%	0.00%	0.00%	0.25%
17	Direct Assign Street Lighting	DASL	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
18	On + Off Sales MWH	E8760	100.00%	29.93%	69.72%	3.15%	66.57%	47.72%	12.41%	5.86%	0.58%	0.35%
19	Street Lighting (Dir Assign)	P73	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
20	MWh Sales Excl CIP Exempt	E99XCIP	100.00%	30.92%	68.63%	3.11%	65.519%	49.87%	11.54%	3.45%	0.66%	0.46%
21	Present Rev	R01	100.00%	37.41%	61.72%	3.50%	58.22%	43.54%	9.92%	4.30%	0.46%	0.87%
22	Late Fee Revenue Allocator	LateFee	100.00%	86.07%	13.84%	5.65%	8.19%	7.75%	0.41%	0.01%	0.02%	0.09%

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
EXTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
23	Customers - B Basis	C10	1,329,086	1,185,737	137,584	88,362	49,222	48,719	479	15	9	5,765
24	Cust - Ave Monthly (C10-Area Lt)	C11	1,355,363	1,189,448	137,784	88,563	49,222	48,719	479	15	9	28,131
25	Mo Cus Wtd By Cus Acct	C11WA	1,430,425	1,189,448	235,212	132,844	102,368	100,941	1,348	51	29	5,765
26	Cust Acctg Wtg Factor	C11WAF	13.98	1.00	12.98	1.50	11.48	2.07	2.81	3.38	3.22	N/A
27	Cust-Ave Mo (C11 w/ Dir Assign S	C12	1,329,763	1,189,448	137,784	88,563	49,222	48,719	479	15	9	2,531
28	Mo Cus Wtd By Mtr Invest	C12WM	170,408,154	113,292,404	56,754,041	16,849,089	39,904,952	37,492,155	2,313,203	62,595	36,999	361,709
29	Meter Invest / Cust Factor	C12WMF	14,311	95	14,073	190	13,883	770	4,829	4,173	4,111	143
30	Sec & Pri Customers	C61PS	1,329,062	1,185,737	137,560	88,362	49,198	48,719	479	0	0	5,765
31	% Served by Primary Single Phase		0.0%	73.59%	0.00%	39.93%	0.00%	11.80%	18.18%	0.00%	0.00%	39.28%
32	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	915,928	872,539	41,124	35,286	5,838	5,751	87	0	0	2,265
33	C62Sec, w/o Ltg & C/I Undergrou	C62NL	1,249,160	1,185,737	63,423	40,882	22,541	22,541	0	0	0	0
34	Secondary Customers	C62Sec	1,328,583	1,185,737	137,081	88,362	48,719	48,719	0	0	0	5,765
35	Summer Peak Resp KW	D10S	25,491	9,833	15,658	866	14,793	11,043	2,636	993	121	0
36	Dmd (D10S x Fact + D10W)/1000	D10T	10,000,000	3,581,601	6,385,863	333,614	6,052,249	4,473,606	1,067,963	462,852	47,828	32,536
37	Winter Peak Resp KW	D10W	4,141	1,322	2,787	135	2,652	1,935	462	234	20	32
38	Alternative Production Allocator	1CP	25,491	9,833	15,658	866	14,793	11,043	2,636	993	121	0
39	Sec, Pri & TT, Class Coin kW @ S	D60Sub	6,484,843	2,711,697	3,737,224	260,498	3,476,726	2,844,845	640,463	(8,582)	0	35,922
40	Sec & Pri, Class Coin kW (w/o Mir	D61PS	5,827,222	2,134,644	3,673,508	195,604	3,477,904	2,809,781	668,123	0	0	19,070
41	Pri & Sec Coin kW Served w/ 1 Pl	D61PS1Ph	2,109,554	1,570,805	531,259	78,112	453,147	331,670	121,477	0	0	7,491
42	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	10,486,622	7,807,161	2,679,460	216,700	2,462,760	2,462,760	0	0	0	0
43	Sec, Class Coin kW (w/o Min Sys	D62SecL	10,000,000	4,935,395	5,039,122	361,546	4,677,576	4,677,576	0	0	0	25,483
44	Annual Billing kW	D99	49,661.671	0	49,662	0	49,662	37,725	7,863	3,579	496	0
45	Summer Billing kW	D99S	18,171.839	0	18,172	0	18,172	13,729	2,954	1,301	188	0
46	Winter Billing kW	D99W	31,489.831	0	31,490	0	31,490	23,996	4,909	2,278	308	0
47	Non-Coinc Pk Second	DN-Sec	13,617,552	7,807,161	5,791,322	468,371	5,322,950	5,322,950	0	0	0	19,070
48	MWh Sales	E99	28,303,153	8,293,789	19,887,270	834,457	19,052,812	13,451,925	3,625,493	1,798,766	176,628	122,095
49	MWh Sales Excl CIP Exempt	E99XCIP	26,826,760	8,293,789	18,410,877	834,295	17,576,581	13,377,890	3,095,346	926,718	176,628	122,095
50	Late Fee Revenue Allocation	LateFee	100.00%	86.07%	13.84%	5.65%	8.19%	7.75%	0.41%	0.01%	0.02%	0.09%

Xcel Energy®

Destination 2050
Building the Future

ANNUAL REPORT

Destination **2050**

Our bold carbon-free **FUTURE**

Xcel Energy has long been a leader in delivering clean energy while maintaining outstanding reliability and affordability. Back in 2005, we were the leading utility wind energy provider in the country, despite the fact that wind comprised only 3 percent of our generation. By 2027, we expect renewable energy — the vast majority being wind — will account for 48 percent of our mix and will be our largest source of energy for our customers.

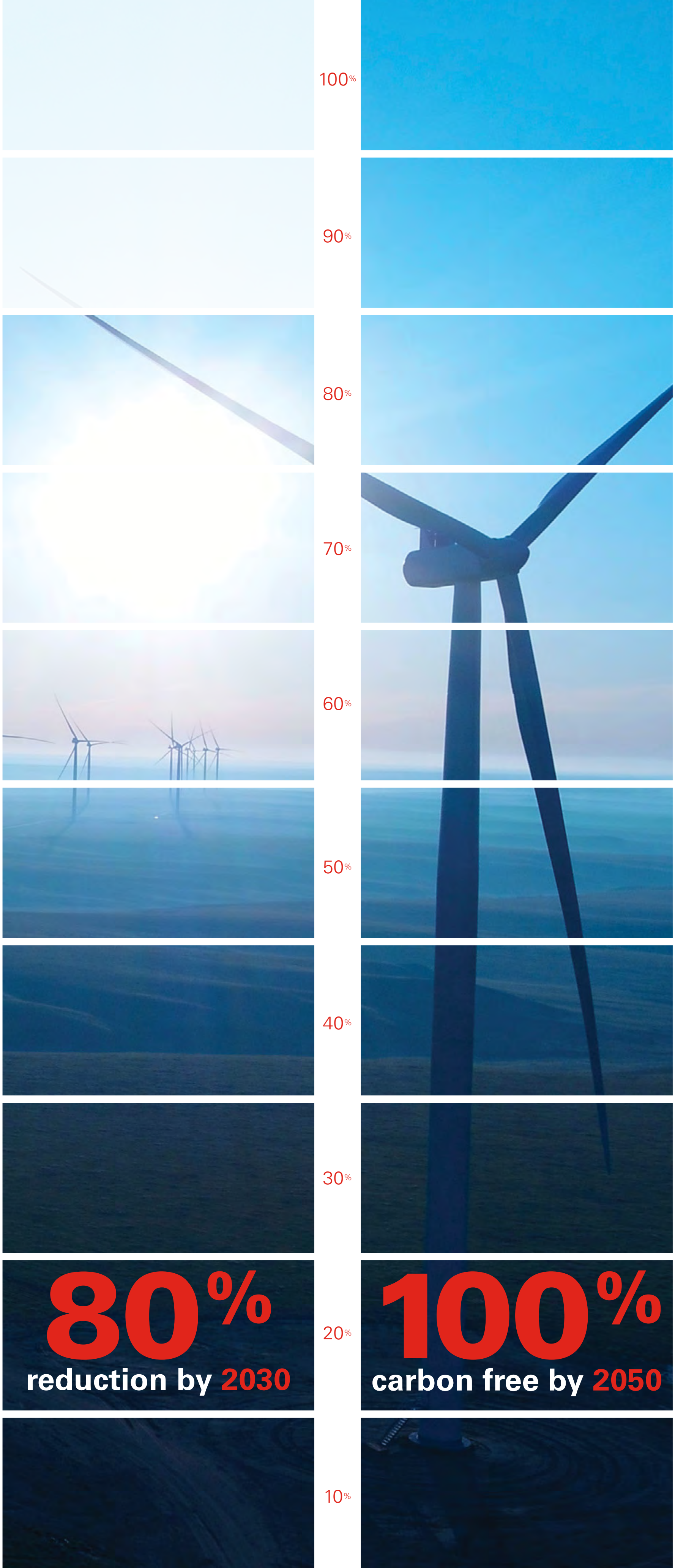
Along the way, we've made steady progress reducing carbon dioxide by transitioning away from fossil fuels, incorporating renewables and developing award-winning energy efficiency programs. Our 2018 carbon emissions are approximately 40 percent lower than our 2005 baseline. That progress put us on pace to hit our previous goal of reducing carbon 60 percent across all eight states in which we do business by 2030.

But a confluence of market forces — improving technology, falling prices and the risk of climate change — convinced us that we can do more, sooner. That's why in December, we became the first electric utility in the country to announce our aspiration to produce 100-percent carbon-free electricity for customers by 2050. At the same time, we announced a new interim target of reducing carbon dioxide emissions 80 percent by 2030.

Significant advances in technology and our ability to integrate high levels of renewable energy onto our system give us the confidence that we expect to hit our 80 percent target by 2030 using existing technologies. To produce 100-percent carbon-free electricity for customers by 2050 will require a dispatchable carbon-free energy source that is not available today. Of course, reliability and affordability must be part of the equation to successfully arrive at our destination.

Setting our sights on this ambitious vision — Destination 2050 — allows us to drive the conversation rather than react to it. It also gives us time for the development of technologies not currently available that will be critical for achieving 100-percent carbon-free electricity. And as important, it gives us a long runway to work with our local communities and employees to help prepare for a clean energy economy.

We're excited to make advances toward Destination 2050 and can't wait to build the future together.



Some sections in this annual report, including the letter to shareholders, contain forward-looking statements. For a discussion of factors that could affect operating results, please see management's discussion and analysis listed in the table of contents of the Form 10-K.

Ben Fowke, Chairman,
President and CEO

Dear Fellow Shareholders:

2018 was a year of significant accomplishments for our company. While we achieved outstanding financial performance, marked major milestones in our Steel for Fuel strategy, and partnered with other utilities to restore power in Puerto Rico following Hurricane Maria, it was our announcement that we see a path to achieve 100-percent carbon-free energy by 2050 that took the spotlight.

Xcel Energy has long been a leader in clean, renewable energy, but we took that to a new level when we became the first major U.S. electric company to announce a carbon-free vision — to serve customers with zero-carbon electricity by 2050. "Destination 2050: Building the Future" captures our long-range vision. But our vision to deliver 100-percent carbon-free energy by 2050 is more than just words. I like to think that we are not just talking about the future, we're building it today.

Outstanding Financial Performance

For the 14th consecutive year, we met or exceeded our earnings guidance. We delivered 2018 GAAP and ongoing earnings of $2.47 per share, at the top end of our original earnings guidance range, compared to GAAP earnings of $2.25 per share and ongoing earnings of $2.30 per share in 2017.

Xcel Energy also increased your dividend 5.6 percent in 2018, extending our streak of dividend growth to 15 consecutive years. We maintained our dividend objective of 5 to 7 percent annual growth, which reflects our confidence in our long-term financial plan.

Strong earnings were driven in part by positive sales growth, particularly to support oil and gas production in Texas and New Mexico. Electric sales increased 1.3 percent and natural gas sales increased 2.4 percent, indicating strong customer growth despite continued advances in energy efficiency.

Because our financial results were so strong during the first two quarters, we made the strategic decision to reinvest earnings into our business for system maintenance and vegetation management. This was a factor in our 3.6 percent increase in operating and maintenance (O&M) expenses in 2018. We remain committed to our long-term objective of improving operating efficiencies and eliminating costs to deliver greater value to our customers and shareholders.

As a result of our continued strong performance, our total shareholder return has outpaced our peer group. Our three-year total shareholder return was 51.1 percent compared to 34.6 percent for our peer group, and our five-year return was 109.5 percent compared to 65.9 percent for our peer group. In addition, our stock price (ticker: XEL) closed at an all-time high of $53.68 in December, and has subsequently set several new all-time highs in early 2019.

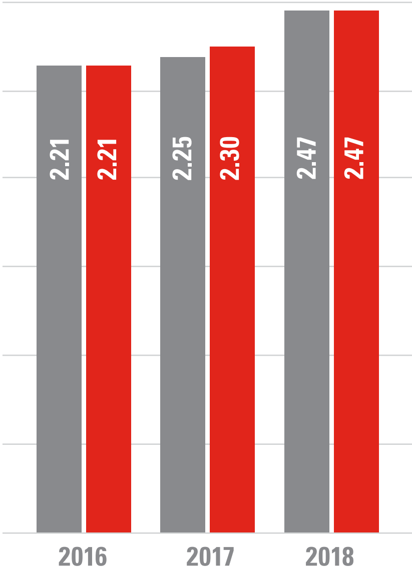
Building the Future Today

We continue to make strong progress in executing our Steel for Fuel growth strategy and are well-positioned to lead the clean energy transition and deliver strong shareholder value for years to come. Developing and owning wind farms brings our customers low-cost, carbon-free wind energy, while it creates economic development for communities and new investments for shareholders. It is a win-with-wind strategy that appeals to multiple stakeholders.

Our Steel for Fuel wind strategy is visible on the eastern plains of Colorado, where the largest wind farm we've ever built —

XCEL ENERGY EARNINGS PER SHARE

Dollars per share (diluted)



GAAP (generally accepted accounting principles) earnings per share

Ongoing earnings per share*

*A reconciliation to GAAP earnings per share is located in Item 7 of the Form 10-K.

FINANCIAL HIGHLIGHTS

	2017	2018
Total GAAP earnings per share	2.25	2.47
Ongoing earnings per share	2.30	2.47
Dividends annualized	1.44	1.52
Stock price (close)	48.11	49.27
Assets (millions)	43,030	45,987

Company description
Xcel Energy is a major U.S. electric and natural gas company with annual revenues of $11.5 billion. Based in Minneapolis, Minnesota, the company operates in eight states and provides a comprehensive portfolio of energy-related products and services to 3.6 million electricity customers and 2 million natural gas customers.

the 600-megawatt Rush Creek Wind Farm — began producing enough carbon-free energy to power 325,000 homes.

We are in the midst of one of the largest multi-state wind expansions in the country. With the completion of Rush Creek in Colorado, we have 11 remaining wind farms under development. In 2018, we secured the last of the necessary approvals for the projects, eight of which we will own. Five wind farms will be completed this year, with five expected to come online in 2020. The Dakota Range Wind Farm in South Dakota is set to begin service in 2021 after the production tax credit begins to phase down.

But, we aren't stopping there. We need to make progress every day to meet our vision of providing carbon-free electricity for customers by 2050 and reducing carbon emissions 80 percent system wide by 2030 (compared to 2005 levels). At the end of 2018, we had reduced carbon emissions by approximately 40 percent.

Our carbon footprint will continue to shrink following the approval of our Colorado Energy Plan, which includes the early retirement of two coal units at the Comanche Generating Station in Pueblo, and replacing that generation with a combination of wind, solar, battery storage and natural gas. By 2026, when all these projects are complete, more than half of the energy we produce in Colorado will come from renewable sources.

Another innovative way to provide Steel for Fuel ownership opportunities for shareholders is to buy out existing power purchase agreements. Late last year we announced agreements to buy two older wind farms in southern Minnesota and re-power them with today's advanced wind technology. While those always require regulatory approval, we intend to continue to pursue similar opportunities in 2019 and beyond.

Enhancing the Customer Experience

Leading the clean energy transition positions us to better serve our customers as we develop new programs to help them achieve their sustainability goals. Last year our all-renewable program in Minnesota and Colorado completely sold out. Renewable*Connect gives customers the opportunity to purchase up to 100 percent of certified renewable energy to power their homes and businesses. We have filed plans for a second phase of this program in Minnesota, this time uncapped and scalable, so we can meet the growing demand for this entirely clean energy product. A similar program has been approved in Wisconsin and will provide a greener option for customers starting later in 2019.

A growing percentage of customers want to reduce their carbon footprint not only in their homes or businesses, but in the vehicles they drive as well. Electric vehicles are a growing consumer choice, and we are taking a three-pronged approach to help our customers seamlessly make the transition. We have several pilots underway in Minnesota to provide home charging options and public charging infrastructure, and to partner with communities and business customers to convert their fleets from traditional to electric vehicles. We recently announced a $25 million investment in electric vehicle infrastructure and believe these pilots will help our customers reduce energy and meet their sustainability needs. We expect to expand our electric vehicle efforts to other states in 2019 and beyond (read more on pages 10-11).

Building a smarter and stronger energy grid that better serves customers is at the heart of our Advanced Grid Intelligence and Security initiative. As technology continues to advance, we are ensuring the way we deliver electricity to homes and businesses keeps improving too. Through this effort we will upgrade our infrastructure, improve security and reliability and leverage advanced meters to provide customers more choices for managing their energy use. We will begin installation of new meters in Colorado late in 2019 and plan to file for approval for our advanced grid initiative in Minnesota this year.

Regulatory Advancements

Effective stakeholder engagement is an important part of generating favorable regulatory outcomes, and we had several regulatory accomplishments in 2018, starting with approvals of our wind projects in Texas and New Mexico.

Colorado regulators approved our long-term pricing agreement with EVRAZ, a large steel mill and the second-largest employer in Pueblo. This agreement was crucial for EVRAZ to continue its operation in Pueblo and allow for expansion into the future.

One of the largest regulatory issues across our service territory in 2018 was working with our policy makers and stakeholders to determine the best way to distribute tax reform benefits to our customers without negatively impacting our credit metrics. Solutions varied by jurisdiction, but in all, we are in the process of returning more than $300 million of tax benefits to our customers.

Regulators are reviewing our purchase agreement of the Mankato Energy Center, a natural gas facility currently under expansion that has served our customers through a PPA contract. We believe that natural gas will serve as an important bridge fuel that works well with high levels of renewable penetration.

While we prepare for our next Upper Midwest resource plan that will be filed in the summer of 2019, we will include a dialogue with the Minnesota commission about the importance of operating our nuclear plants through their license periods in the early 2030s. It's important that we operate our fleet efficiently and effectively, which is exactly what we did in 2018. The fleet delivered energy 96 percent of the time, while reducing its O&M costs by almost 3 percent (read more on pages 12-13).

Operational Excellence

At the heart of Xcel Energy's culture is the commitment to getting better every day. We've engaged our employees to find innovative ways to reduce costs and gain efficiencies, and they have delivered. By implementing continuous improvement suggestions from our employees, we saved $59 million of O&M expenses in 2018. We also developed the in-house expertise in lean management techniques to apply continuous improvement efforts to other areas of the business in 2019 and beyond.

Our always-improving mindset is also at work when it comes to safety, of our employees and the public. In 2018, we built a state-of-the-art natural gas training facility in Minnesota to better train employees and the first responders who we work with in our communities. I am pleased that we had our best public safety performance ever, as measured by gas emergency response, and achieved first quartile performance when it comes to employee safety. We've reduced employee injuries by more than 50 percent since we implemented our Journey to Zero employee safety program.

Living Our Values

We refreshed our corporate values in 2018 to bring a sharp focus and intention to how we want all of our 11,000 employees to approach their work each and every day. These new values — Connected, Committed, Safe and Trustworthy — were crafted and refined with employees engaged along the way.

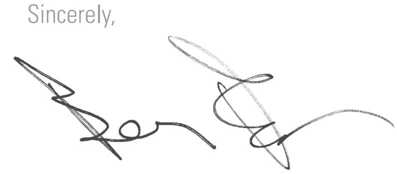
Exceptional people, grounded in a values-driven organization, is a winning combination that's getting noticed. Xcel Energy has been fortunate to receive recognition from publications like *Forbes* and *Fortune*, which have repeatedly listed us as among the world's best companies. *Utility Dive* named Xcel Energy its 2018 Utility of the Year, and we were chosen among the 100 Best Corporate Citizens by *Corporate Responsibility Magazine*.

One of the things I am most proud of is our collective commitment to the communities where we serve. In the last year we gave back in a big way, donating more than $11 million and 90,000 volunteer hours to community organizations. Our efforts could be felt in everything from environmental improvements like tree plantings and other greening, to supporting economic self-sufficiency through mentoring and training efforts.

As we continue to build the future, we have Destination 2050 squarely in our sights. But as you can see, it is about more than just reducing our carbon footprint and delivering 100-percent carbon-free energy to our customers and communities by 2050. Destination 2050 is about always innovating to deliver best-in-class service to our customers, standing squarely with our communities to help them achieve their energy and economic development goals, engaging with our employees so they can bring their best to work every day and making an impact in our own backyards.

Thank you to our customers, shareholders, employees and stakeholders for helping make 2018 an outstanding year for Xcel Energy.

Sincerely,



Ben Fowke
Chairman, President and
Chief Executive Officer

In 2018, Xcel Energy successfully moved into the execution stage for one of the largest multi-state wind investments in the country. The first project completed is Rush Creek in Colorado.

Wind projects receive green light

Wind farms aren't built just anywhere land is for sale. They are complex projects that require extensive planning and permitting, significant outreach to neighboring property owners and other stakeholders, and, of course, regulatory approval.

It's one thing to propose new wind projects. It's another to shepherd them through the approvals necessary to get new wind farms constructed. Last year, we were able to secure the last of the necessary approvals for one of the largest multi-state wind investments in the country — 12 wind farms in seven states. The first wind project, Rush Creek in Colorado, was completed in 2018.

Appropriately, state and local interests drive the discussion. Some communities and regulators are focused on wind energy's ability to save customers money and to drive economic development. Others are attracted to the fact that more wind energy on our system allows us to continue reducing carbon emissions. What makes our Steel for Fuel strategy of building and owning wind farms widely appealing is its ability to deliver both economic and environmental benefits.

New wind farms and the accompanying substations and transmission lines needed to deliver the energy to market are powerful sources of economic development, often in rural areas. Our multi-state wind expansion is expected to create 2,700 construction jobs and 150 full-time positions, and generate $800 million in landowner lease and property tax payments over the lives of the projects.

By 2027, we expect 39 percent of our energy will be supplied by wind — nearly double the amount on our system in 2017. That means wind energy would generate enough clean energy to power approximately six million homes and avoid more than 28 million tons of carbon emissions annually.

Colorado Energy Plan Gains Approval

We have secured regulatory approval for our Colorado Energy Plan, which will allow Xcel Energy to deliver on our vision to provide low-cost, clean renewable energy for our customers, stimulate economic development in rural Colorado and substantially reduce our carbon emissions.

This project required significant stakeholder outreach and engagement and received support from more than 20 business groups and environmental organizations. The Colorado Energy Plan paves the way for the early retirement of two coal units at the Comanche Generating Station in Pueblo. When fully executed in 2026, 55 percent of our Colorado energy mix is expected to come from renewable sources while saving customers money on their bills.

The first wind project in the Colorado plan — a 500-megawatt wind farm called Cheyenne Ridge — is expected to be completed in late 2020, assuming final regulatory approvals are secured.

All charged up about driving electric

EV initiative focused on the customer experience

Twin Cities software engineer Adam Carstensen purchased his first EV — a Tesla Model 3 — in November 2018. A few weeks before delivery, Adam contacted Xcel Energy to set up charging equipment in his garage.

The timing was perfect. The Minnesota Public Utilities Commission just approved an EV pilot program to provide advanced home charging equipment for 100 residential customers. The program was advantageous for Adam because the new equipment charges EVs faster than previous technology and includes energy monitoring technology that eliminates the need to install a new dedicated meter and service solely for EV charging.

"Once the pilot opened, I responded within a minute. I was one of the first customers in Minnesota to receive the new charging equipment. Not having to install a second meter saved me $1,700 dollars. It was a great experience — very seamless," Adam said.

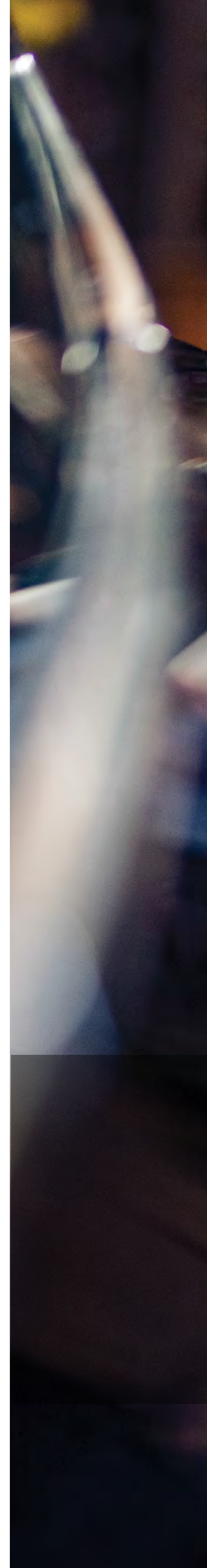
Adam can drive up to 300 miles on a full charge. He drives his Tesla 25 miles to and from work each workday and uses it for trips throughout the Twin Cities without thinking twice. For longer trips, he plans ahead using an app on his phone that shows where public fast-charging stations are located.

Once he's done driving for the day, Adam plugs in his vehicle at home. At 9:00 each evening, the charging process automatically begins on Xcel Energy's EV electric pricing plan, which is more than 50 percent lower than standard residential pricing. Because the need for electricity demand falls at night, EV owners are encouraged to save money by charging overnight. Charging an EV on Xcel Energy's off-peak plan is the equivalent to approximately 50 cents per gallon.

"I save about $40 dollars a month in fuel costs," said Adam, who also took advantage of a $7,500 federal tax credit. "The bigger savings comes from maintenance. The only regular maintenance I have is rotating the tires and filling up the windshield-washer fluid. There is no engine — no oil changes."

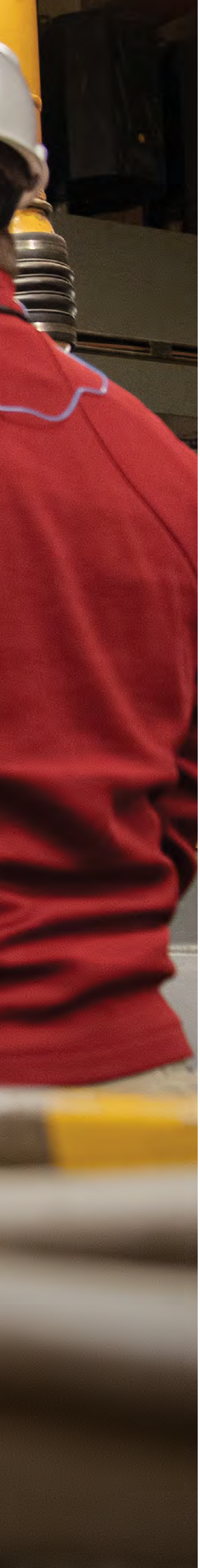
Although EV customers can realize cost savings compared to traditional vehicles, Adam first began researching hybrid and EVs because of the environmental benefits. Today, a conventional car emits 5.2 tons of carbon dioxide per year. By comparison, EVs charged on Xcel Energy's system in Minnesota produce only 1.5 tons of carbon per year. That number is expected to drop to 0.4 tons by 2030 as our electricity becomes greener and greener. Adam's car doesn't produce any carbon emissions when it's charged at home because he also participates in our Renewable*Connect program at the 100 percent level, meaning all the electricity in his house comes from certified wind or solar renewable energy sources.

"EVs are better for the environment. Climate change is a real problem and this is something that we could do to try and help," said Adam, who is concerned about the planet his two young children will inherit.



Adam Carstensen (left), a participant in the new Minnesota electric vehicle home charging pilot program, goes over his home charging equipment with Neal Callinan of Xcel Energy.

Ben Fowke, Chairman, President and CEO, visits with employees at our Prairie Island nuclear facility near Red Wing, Minnesota.



Nuclear checks all the boxes

We've long appreciated the value nuclear energy delivers on a number of fronts: the "round-the-clock" affordable energy it provides, the environmental benefits of carbon-free generation, and the $1 billion of annual economic impact to the Minnesota economy where our plants are located.

An increasing number of stakeholders have come to appreciate nuclear power for those same reasons. The carbon-free nature of nuclear energy, coupled with its 24x7 power, make it extremely valuable to the clean energy transition.

The clean energy transition cannot work if reliability and affordability are not part of the equation. Reliable, affordable and clean must work together, and nuclear energy checks all the boxes.

For us, a critical part of our clean energy vision is operating our nuclear units at least through their current licenses, which expire in the early 2030s. We operate three nuclear units in Minnesota — one at Monticello and two units at Prairie Island — that provide 13 percent of our energy mix. Because nuclear energy provides the only carbon-free, always on energy source for our system, it makes pragmatic sense that nuclear remains an important part of our energy future.

Employees working at our nuclear plants understand that running those facilities safely, effectively and efficiently is of the utmost importance. During the last few years, we've empowered our team to drive innovation to reduce costs — and they've delivered. In the last three years, our nuclear employees have eliminated about $40 million of operating and maintenance costs. In 2018, our nuclear employees set a generation record, producing more than 14.6 million megawatt hours of energy, all without a lost-time injury. In addition to working safely, last year the team worked effectively and efficiently, producing power 96 percent of the time while reducing its operating and maintenance costs by nearly 3 percent — a winning formula.

We've also found innovative ways to reduce fuel costs. By developing a new fuel design, the nuclear engineering team significantly reduced the amount of fuel consumed during operations. This approach extends the period of time between scheduled refueling from 18 months to 24 months, which will save approximately $4 to $5 million per year in fuel costs. Additionally, we expect to generate $70 million in savings over the next 15 years as the need for two refueling outages will be eliminated.

Clean, affordable, reliable. Nuclear energy produced in Minnesota continues to check all the boxes.

A sight to behold, from a distance

Forty miles north of Denver, a first-of-its-kind unmanned aircraft system flight took place last summer. Very few people saw it — and that's the point.

In 2018, Xcel Energy became the first public utility in the country to receive permission from the Federal Aviation Administration (FAA) to fly drones beyond the operator's line of sight to inspect transmission lines. The flights, which began in July and continued monthly through the year, are part of a program to prove the value of using unmanned aircraft to inspect critical infrastructure in the power generation industry.

The Altus ORC2, a 35-pound drone not available in the retail market, collected images and volumes of data that was then analyzed to identify potential issues that could impact the reliability of the electric transmission grid. More than 1,000 miles of test flights were tracked by a field operations team of four individuals located on the ground — a pilot, an observer and two other team members monitoring the data collection.

"FAA team members came to Colorado to observe our transmission inspection flights first hand," said Eileen Lockhart, who manages Xcel Energy's UAS program. "They were pleased with the results. If all continues to go well, the program will be expanded to our peer companies in the future."

As a regulated utility, Xcel Energy is required to inspect and perform maintenance on its transmission lines — 24,000 miles of them — on a routine basis. Traditionally we have conducted these inspections with helicopters and foot patrols. Using drones to inspect transmission lines delivers value on many fronts, starting with ensuring the reliability for our customers thanks to better data capture.

It's also safer for our employees, especially in remote mountainous areas, and less expensive, which is one of the many ways we're working to keep customers' bills low. As technology improves, the cost to operate drones continues to fall, which saves even more money for customers.

Pending FAA approval, we plan to expand this program to inspect transmission lines in other states beginning in 2019. Additionally, we are collaborating with the FAA and the state of North Dakota on the National UAS Integration Pilot Program, an opportunity for state, local, and tribal governments to partner with private-sector entities to work together to accelerate drone integration.

Xcel Energy began using drones to conduct indoor inspections in 2013 and expanded the program for outdoor use in 2015. We use drones to inspect everything from boilers to wind towers to our nuclear facilities and everything in between.

Xcel Energy became the first public utility to receive permission from the Federal Aviation Administration to inspect transmission lines using drones flown beyond the operator's visual line of sight.

Xcel Energy crews work to safely restore power in Caguas, a mountainous region in southeastern Puerto Rico.

A powerful experience in Puerto Rico

Some of the most rewarding work of 2018 took place more than a thousand miles from our closest service territory. Approximately 200 Xcel Energy line workers and support personnel traveled to Puerto Rico to help restore power following the devastation of Hurricane Maria.

Three waves of Xcel Employees flew to Puerto Rico for three-week assignments on the Caribbean island, while our trucks and equipment arrived by barge after being driven to Lake Charles, Louisiana. Xcel Energy crews worked primarily in Caguas, a mountainous and remote region where restoration efforts were challenging due to rugged terrain, narrow roads and overgrown vegetation.

Crews worked 16-hour days to safely restore electricity for approximately 6,000 customers, including homes, schools, community centers and one church just in time to hold Easter services. Xcel Energy was among nearly 60 investor-owned electricity companies that collectively dispatched 3,000 line workers and support personnel to restore power as part of the industry's mutual aid program. Xcel Energy was one of several companies to be recognized with a special 2018 Emergency Assistance Award by the Edison Electric Institute.

"Traveling to Puerto Rico was one of the most rewarding experiences in my career," said Lee Nordby, who oversaw Xcel Energy's restoration efforts on the island. "Many of the people we encountered had been without power for three or four months, but they were so positive and grateful for our efforts."

Local residents thanked our crews with home-cooked meals, hugs and thank-you signs. One of the most moving events happened at a school where a 12-year-old cried tears of joy after we granted her birthday wish — to restore power after nearly five months in the dark.

"It was really powerful," said Mike Bulger, an operations manager from Colorado. "Our crews restore electricity all over the United States when called upon, but our experience in Puerto Rico was special — something that none of us will ever forget."

Xcel Energy co-sponsored an exhibition at Super Bowl LIVE, a week-long celebration that was powered by 100-percent renewable energy. The space included a display for children to illuminate the Super Bowl logo in lights.

Reliable power for the world's biggest stage

A few years ago, a power outage played a memorable role at the Super Bowl in New Orleans. Xcel Energy was determined to make sure that didn't happen in our backyard. As expected, Super Bowl LII between the Philadelphia Eagles and the New England Patriots went off without a hitch in downtown Minneapolis.

It was an honor to provide power for the biggest game on the world's biggest stage — more than 103 million people watched the game on television. Employees from our operations and security teams worked nearly two years performing reliability inspections, maintaining infrastructure, and identifying risk for every possible contingency leading up to the game that was played February 4, 2018 at U.S. Bank Stadium.

Xcel Energy proudly served as the official Renewable Energy Provider of the Minnesota Super Bowl Host Committee. All of the power needed for Super Bowl LIVE — a week-long celebration down the street from our corporate headquarters on Nicollet Mall — was powered through our WindSource® program with 100 percent of the energy coming from Minnesota wind farms. Xcel Energy and Vestas, our wind turbine manufacturing supplier, jointly sponsored an exhibition at Super Bowl LIVE that was staffed by our employee volunteers. More than a million people participated in a variety of events leading up to the big game.

We plan to use the same playbook to ensure things go smoothly during the next large sporting event in downtown Minneapolis — the NCAA Final Four men's basketball championship — that will take place at the same location in April 2019.

A thoughtful approach to building a diverse workforce

It's important for our workforce to reflect the diversity of the communities we are privileged to serve. We have taken a thoughtful approach to workforce development as we know that diverse organizations are more successful because they bring different strengths and perspectives to the table.

This includes expanding our award-winning internship programs, creating customized diverse hiring and retention plans for select business units, developing unconscious bias training for all employees and participating in the CEO Action for Diversity & Inclusion, a national program focused on diverse hiring and retention best practices.

For many years, we have been actively engaged with high school internship programs in the Twin Cities, Denver and Eau Claire, and we recently launched a new high school internship program in Amarillo, Texas. In 2018, we hired a record 66 high school interns, and the timing couldn't be better as it aligned with the launch of a new social media platform developed by Xcel Energy and Greater MSP to help Twin Cities companies to better track local interns and keep them in the pipeline for permanent employment.

We also partner with Legacy i3 — a unique program that encourages students from underrepresented communities to pursue careers in the energy industry and directs them to our educational partners who provide career training opportunities. This includes working with Minnesota State Colleges and Universities to guide these students into energy-related programs for line workers and technical specialists. Xcel Energy employees mentor these program participants through our Energy Ambassador program.

All these programs help us share with a broader audience our story that Xcel Energy is a great place to work, while we build candidate pipelines in communities where this story has not been well known in the past. Our high school and college internship programs have proven to be strong sources of diverse talent.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2018

or

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

001-3034	41-0448030
(Commission File Number)	(I.R.S. Employer Identification No.)

(Registrant, State of Incorporation or Organization, Address of Principal Executive Officers and Telephone Number)

Xcel Energy Inc.

(a Minnesota corporation)
414 Nicollet Mall
Minneapolis, MN 55401
612-330-5500

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, $2.50 par value per share	Nasdaq Stock Market LLC

Securities registered pursuant to section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. ☒ Yes ☐ No
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. ☐ Yes ☒ No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☒ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 and Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). ☒ Yes ☐ No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulations S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. ☒ Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☐ Smaller Reporting Company ☐ Emerging growth company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). ☐ Yes ☒ No

As of June 29, 2018, the aggregate market value of the voting common stock held by non-affiliates of the Registrants was $23,246,479,826 and there were 508,898,420 shares of common stock outstanding.

As of Feb. 14, 2019, there were 514,211,368 shares of common stock outstanding, $2.50 par value.

DOCUMENTS INCORPORATED BY REFERENCE

The Registrant's Definitive Proxy Statement for its 2019 Annual Meeting of Shareholders is incorporated by reference into Part III of this Form 10-K.

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PART I

Item 1 — Business

ABBREVIATIONS AND INDUSTRY TERMS

Xcel Energy Inc.'s Subsidiaries and Affiliates (current and former)

Capital Services	Capital Services, LLC
Eloigne	Eloigne Company
e prime	e prime inc.
NCE	New Century Energies, Inc.
NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP System	The electric production and transmission system of NSP-Minnesota and NSP-Wisconsin operated on an integrated basis and managed by NSP-Minnesota
NSP-Wisconsin	Northern States Power Company, a Wisconsin corporation
Operating companies	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
PSCo	Public Service Company of Colorado
SPS	Southwestern Public Service Co.
Utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
WGI	WestGas InterState, Inc.
WYCO	WYCO Development, LLC
Xcel Energy	Xcel Energy Inc. and its subsidiaries

Federal and State Regulatory Agencies

CPUC	Colorado Public Utilities Commission
D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
DOC	Minnesota Department of Commerce
DOE	United States Department of Energy
DOJ	Department of Justice
DOT	United States Department of Transportation
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
Fifth Circuit	United States Court of Appeals for the Fifth Circuit
IRS	Internal Revenue Service
Minnesota District Court	U.S. District Court for the District of Minnesota
MPSC	Michigan Public Service Commission
MPUC	Minnesota Public Utilities Commission
NDPSC	North Dakota Public Service Commission
NERC	North American Electric Reliability Corporation
Ninth Circuit	U.S. Court of Appeals for the Ninth Circuit
NMPRC	New Mexico Public Regulation Commission
NRC	Nuclear Regulatory Commission
OAG	Minnesota Office of the Attorney General
PHMSA	Pipeline and Hazardous Materials Safety Administration
PSCW	Public Service Commission of Wisconsin
PUCT	Public Utility Commission of Texas
SDPUC	South Dakota Public Utilities Commission
SEC	Securities and Exchange Commission
TCEQ	Texas Commission on Environmental Quality

Electric, Purchased Gas and Resource Adjustment Clauses

CIP	Conservation improvement program
DCRF	Distribution cost recovery factor
DSM	Demand side management
DSMCA	Demand side management cost adjustment
ECA	Retail electric commodity adjustment
EE	Energy efficiency
EECRF	Energy efficiency cost recovery factor
EIR	Environmental improvement rider
FCA	Fuel clause adjustment
FPPCAC	Fuel and purchased power cost adjustment clause
GCA	Gas cost adjustment
GUIC	Gas utility infrastructure cost rider
PCCA	Purchased capacity cost adjustment
PCRF	Power cost recovery factor
PGA	Purchased gas adjustment
PSIA	Pipeline system integrity adjustment
RDF	Renewable development fund
RER	Renewable energy rider
RES	Renewable energy standard
RESA	Renewable energy standard adjustment
SCA	Steam cost adjustment
SEP	State energy policy rider
TCA	Transmission cost adjustment
TCR	Transmission cost recovery adjustment
TCRF	Transmission cost recovery factor
WCA	Windsource® cost adjustment

Other

AFUDC	Allowance for funds used during construction
ALJ	Administrative law judge
APBO	Accumulated postretirement benefit obligation
ARAM	Average rate assumption method
ARO	Asset retirement obligation
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
ATM	At-the-market
ATRR	Annual transmission revenue requirement
BART	Best available retrofit technology
Boulder	City of Boulder, CO
C&I	Commercial and Industrial
CAPM	Capital Asset Pricing Model
CACJA	Clean Air Clean Jobs Act
CAISO	California Independent System Operator
CapX2020	Alliance of electric cooperatives, municipals and investor-owned utilities in the upper Midwest involved in a joint transmission line planning and construction effort
CBA	Collective-bargaining agreement
CCR	Coal combustion residuals
CCR Rule	Final rule (40 CFR 257.50 - 257.107) published by the EPA regulating the management, storage and disposal of CCRs as a nonhazardous waste
CDD	Cooling degree-days
CEP	Colorado Energy Plan
CIG	Colorado Interstate Gas Company, LLC
CO_2	Carbon dioxide
Corps	U.S. Army Corps of Engineers
CPCN	Certificate of public convenience and necessity
CPP	Clean Power Plan
CWA	Clean Water Act

CWIP	Construction work in progress
DCF	Discounted Cash Flows
DECON	Decommissioning method where radioactive contamination is removed and safely disposed at a requisite facility, or decontaminated to a permitted level.
DRC	Development Recovery Company
DRIP	Dividend Reinvestment Program
EEI	Edison Electric Institute
ELG	Effluent limitations guidelines
EMANI	European Mutual Association for Nuclear Insurance
EPS	Earnings per share
EPU	Extended power uprate
ERP	Electric resource plan
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
FTR	Financial transmission right
GAAP	Generally accepted accounting principles
GE	General Electric
GHG	Greenhouse gas
HDD	Heating degree-days
HTY	Historic test year
IM	Integrated market
IPP	Independent power producing entity
IRC	Internal Revenue Code
IRP	Integrated Resource Plan
ISFSI	Independent Spent Fuel Storage Installation
ITC	Investment Tax Credit
JOA	Joint operating agreement
LCM	Life cycle management
LLW	Low-level radioactive waste
LSP Transmission	LSP Transmission Holdings, LLC
Mankato 1	Mankato Energy Center, LLC
Mankato 2	Mankato Energy Center II, LLC
MDL	Multi-district litigation
MGP	Manufactured gas plant
MISO	Midcontinent Independent System Operator, Inc.
Moody's	Moody's Investor Services
NAAQS	National Ambient Air Quality Standard
Native load	Demand of retail and wholesale customers that a utility has an obligation to serve under statute or contract
NAV	Net asset value
NEIL	Nuclear Electric Insurance Ltd.
NETO	New England Transmission Owners
NOL	Net operating loss
NOX	Nitrogen oxide
O&M	Operating and maintenance
OATT	Open Access Transmission Tariff
OCC	Office of Consumer Counsel
Opinion 531	Methodology for calculating base ROE adopted by the FERC in June 2014
Paris Agreement	Establishes a framework for GHG mitigation actions by all countries ("nationally determined contributions")
PI	Prairie Island nuclear generating plant
PJM	PJM Interconnection, LLC
PM	Particulate matter
Post-65	Post-Medicare
PPA	Purchased power agreement
Pre-65	Pre-Medicare
PRP	Potentially responsible party
PTC	Production tax credit
QF	Qualifying facilities
R&E	Research and experimentation
REC	Renewable energy credit
RFP	Request for proposal
ROE	Return on equity
ROFR	Right-of-first-refusal
RPS	Renewable portfolio standards
RTO	Regional Transmission Organization
Standard & Poor's	Standard & Poor's Ratings Services
SAB	Staff Accounting Bulletin
SAB 118	Income Tax Accounting Implications of the Tax Cuts and Jobs Act
SERP	Supplemental executive retirement plan
SMMPA	Southern Minnesota Municipal Power Agency
SO2	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
SSL	Statistically significant increase over established groundwater standards
TCEH	Texas Competitive Energy Holdings
TCJA	2017 federal tax reform enacted as Public Law No: 115-97, commonly referred to as the Tax Cuts and Jobs Act
THI	Temperature-humidity index
TOs	Transmission owners
TransCo	Transmission-only subsidiary
TSR	Total shareholder return
VaR	Value at Risk
VIE	Variable interest entity
WOTUS	Waters of the U.S.

Measurements

Bcf	Billion cubic feet
KV	Kilovolts
KWh	Kilowatt hours
MMBtu	Million British thermal units
MW	Megawatts
MWh	Megawatt hours

Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed herein are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including the 2019 EPS guidance, long-term EPS and dividend growth rate, as well as assumptions and other statements are intended to be identified in this document by the words "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should," "will," "would" and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we expressly disclaim any obligation to update any forward-looking information. The following factors, in addition to those discussed elsewhere in this Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2018 (including the items described under Factors Affecting Results of Operations; and the other risk factors listed from time to time by Xcel Energy Inc. in reports filed with the SEC, including "Risk Factors" in Item 1A of this Annual Report on Form 10-K hereto), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: changes in environmental laws and regulations; climate change and other weather, natural disaster and resource depletion, including compliance with any accompanying legislative and regulatory changes; ability of subsidiaries to recover costs from customers; reductions in our credit ratings and the cost of maintaining certain contractual relationships; general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of Xcel Energy Inc. and its subsidiaries to obtain financing on favorable terms; availability or cost of capital; our customers' and counterparties' ability to pay their debts to us; assumptions and costs relating to funding our employee benefit plans and health care benefits; our subsidiaries' ability to make dividend payments; tax laws; operational safety, including our nuclear generation facilities; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices; costs of potential regulatory penalties; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; fuel costs; and employee work force and third party contractor factors.

Where To Find More Information

Xcel Energy's website address is www.xcelenergy.com. Xcel Energy makes available, free of charge through its website, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after the reports are electronically filed with or furnished to the SEC. The SEC maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically at http://www.sec.gov.

COMPANY OVERVIEW

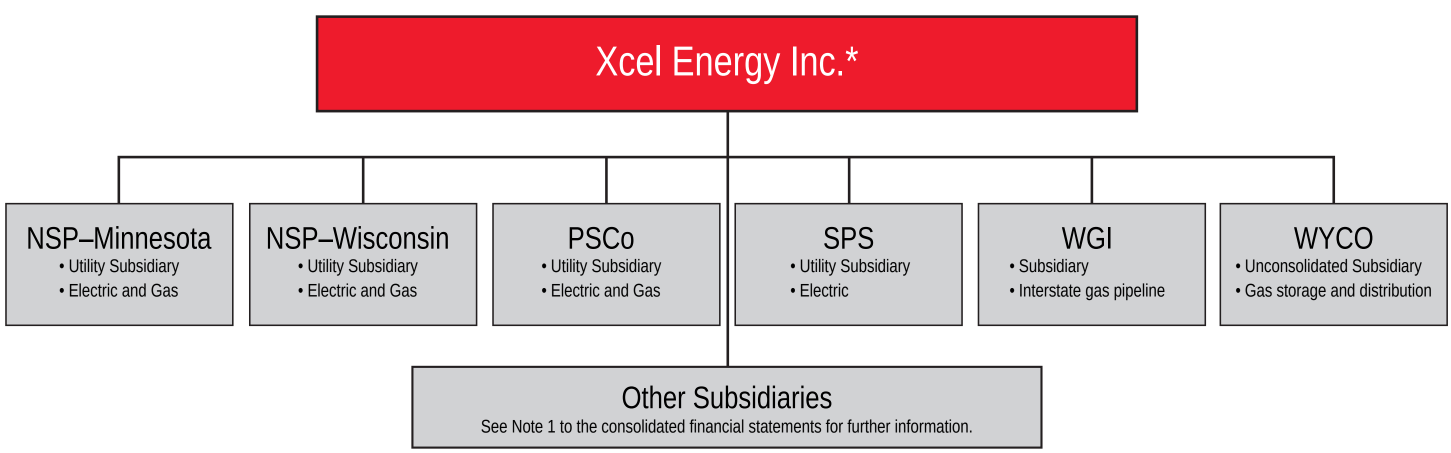
Xcel Energy Inc. and its subsidiaries ("Xcel Energy" or the "Company") is a major U.S. regulated electric and natural gas delivery company which serves customers in eight mid-western and western states, including portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. The Company provides a comprehensive portfolio of energy-related products and services to approximately 3.6 million electric customers and 2.0 million natural gas customers through four operating companies (e.g., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS).

Xcel Energy's vision is to be the preferred and trusted provider of the energy our customers need and we strive to provide our investors an attractive total return value proposition and customers with safe, clean and reliable energy services at a competitive price. This mission is enabled via three key strategic priorities:

- Lead the clean energy transition;
- Enhance the customer experience; and,
- Keep the bills low.

Xcel Energy is an environmental leader and in 2018 was the first major utility in the nation to announce a vision to serve all customers with 100% zero-carbon emissions by 2050. The Company is also implementing the nation's largest multi-state wind plan with 12 new, low-cost wind farms across seven states. By leading the clean energy transition, we have positioned ourselves to create economic development for the communities and customers we serve.

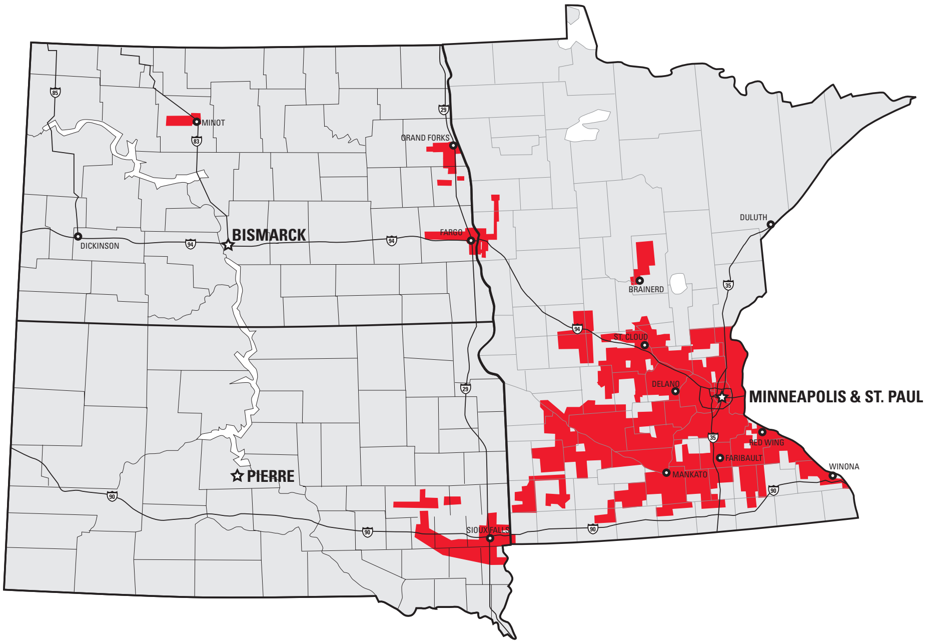
See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Management's Strategic Priorities for further discussion.



* Holding company incorporated under the laws of Minnesota in 1909 and its executive offices are located at 414 Nicollet Mall, Minneapolis, MN 55401.

NSP-Minnesota

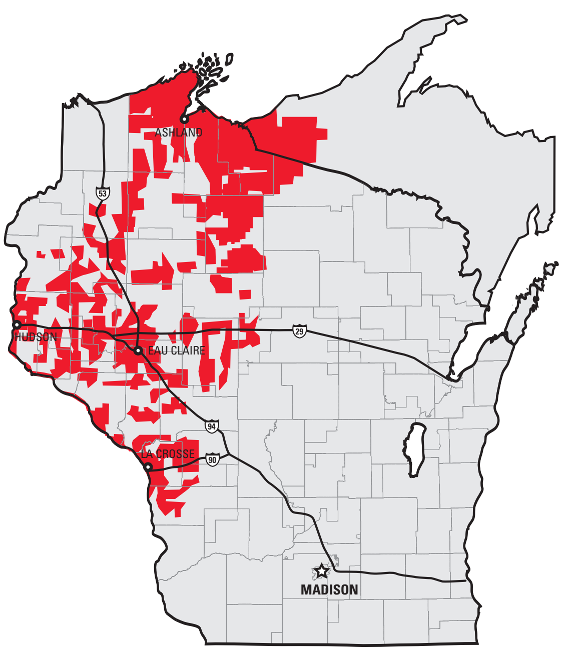
NSP-Minnesota conducts business in Minnesota, North Dakota and South Dakota and has electric operations in all three states including the generation, purchase, transmission, distribution and sale of electricity as managed on the NSP System. NSP-Minnesota also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas in Minnesota and North Dakota.



NSP-Minnesota	
Electric customers	1.5 million
Natural gas customers	0.5 million
Consolidated earnings contribution	35% to 45%
Total assets	$18.5 billion
Electric generating capacity	7,530 MW
Gas storage capacity	14.7 Bcf

NSP-Wisconsin

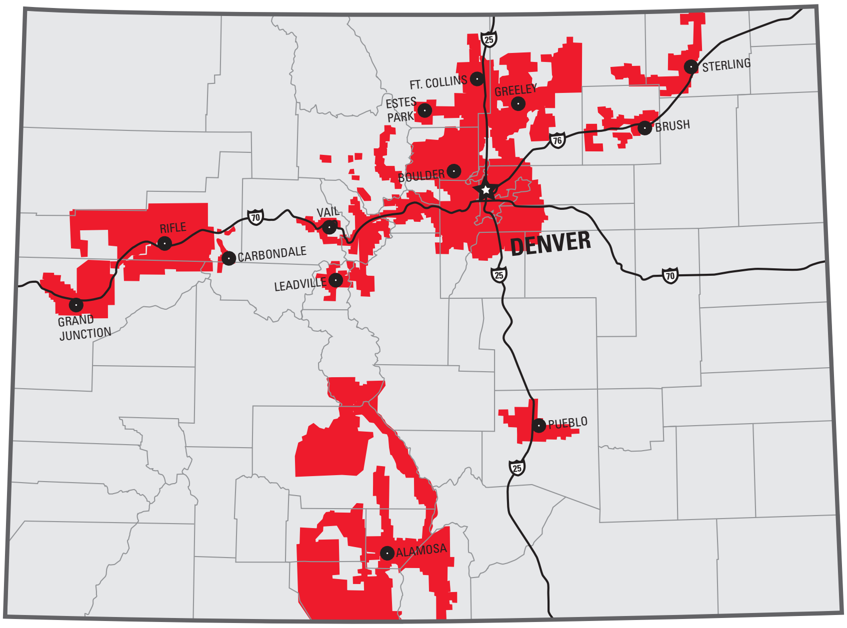
NSP-Wisconsin conducts business in Wisconsin and Michigan and generates, transmits, distributes and sells electricity as managed on the NSP System. NSP-Wisconsin also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas.



NSP-Wisconsin	
Electric customers	0.3 million
Natural gas customers	0.1 million
Consolidated earnings contribution	5% to 10%
Total assets	$2.7 billion
Electric generating capacity	563 MW
Gas storage capacity	3.6 Bcf

PSCo

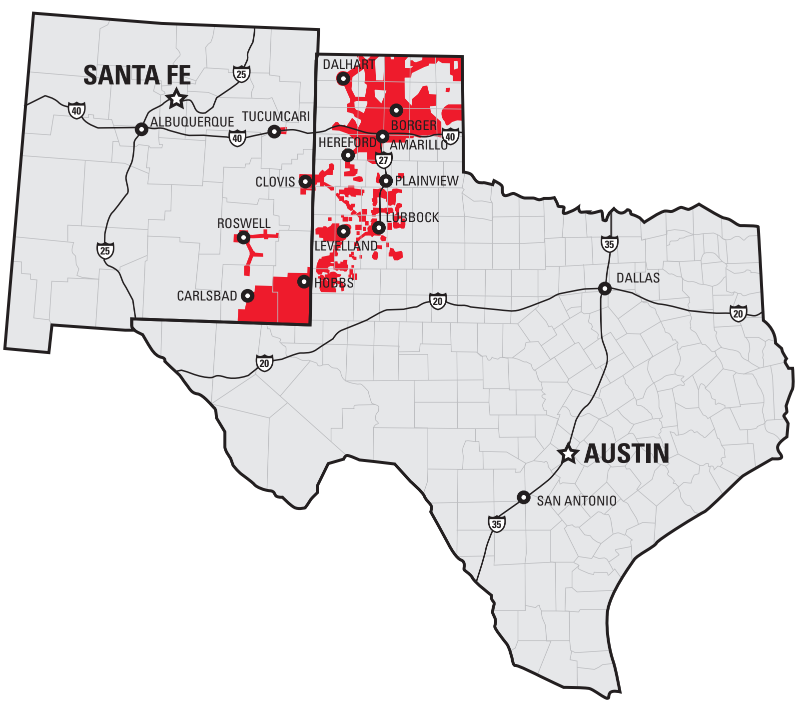
PSCo conducts business in Colorado and generates, purchases, transmits, distributes and sells electricity in addition to purchasing, transporting, distributing and selling natural gas to retail customers and transporting customer-owned natural gas.



PSCo	
Electric customers	1.5 million
Natural gas customers	1.4 million
Consolidated earnings contribution .	35% to 45%
Total assets	$17.3 billion
Electric generating capacity	5,685 MW
Gas storage capacity	27.1 Bcf

SPS

SPS conducts business in Texas and New Mexico and generates, purchases, transmits, distributes and sells electricity.



SPS	
Electric customers	0.4 million
Consolidated earnings contribution .	15% to 20%
Total assets	$6.7 billion
Electric generating capacity	4,406 MW

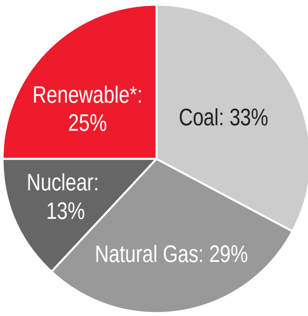
ELECTRIC UTILITY OPERATIONS

Electric Operating Statistics

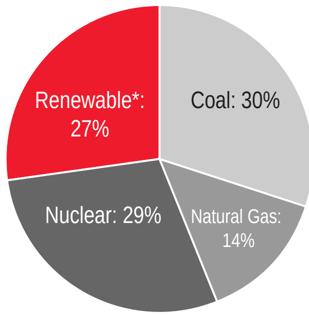
	Year Ended Dec. 31		
	2018	2017	2016
Electric sales (Millions of KWh)			
Residential	25,518	24,216	24,726
Large C&I	28,686	27,951	27,664
Small C&I	36,308	35,493	35,830
Public authorities and other	1,071	1,055	1,103
Total retail	91,583	88,715	89,323
Sales for resale	24,199	18,349	18,694
Total energy sold	115,782	107,064	108,017
Number of customers at end of period			
Residential	3,117,262	3,082,974	3,053,732
Large C&I	1,253	1,241	1,228
Small C&I	436,836	433,883	432,012
Public authorities and other	69,794	69,376	68,935
Total retail	3,625,145	3,587,474	3,555,907
Wholesale	70	58	52
Total customers	3,625,215	3,587,532	3,555,959
Electric revenues (Millions of Dollars)			
Residential	$ 3,006	$ 2,975	$ 2,966
Large C&I	1,696	1,779	1,707
Small C&I	3,343	3,463	3,328
Public authorities and other	136	143	140
Total retail	8,181	8,360	8,141
Wholesale	801	719	693
Other electric revenues	737	597	666
Total electric revenues	$ 9,719	$ 9,676	$ 9,500
KWh sales per retail customer	25,263	24,729	25,120
Revenue per retail customer	$ 2,257	$ 2,330	$ 2,289
Residential revenue per KWh	11.78¢	12.29¢	11.99¢
Large C&I revenue per KWh	5.91	6.36	6.17
Small C&I revenue per KWh	9.21	9.76	9.29
Total retail revenue per KWh	8.93	9.42	9.11
Wholesale revenue per KWh	3.31	3.92	3.71

Energy Sources 2018

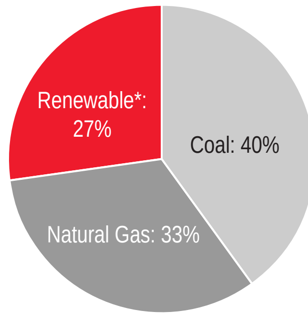
Xcel Energy



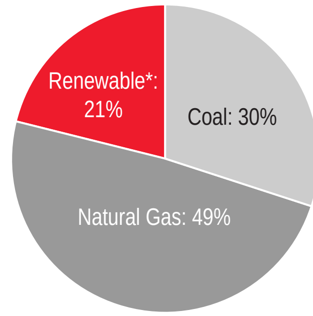
NSP System



PSCo



SPS



*Distributed generation from the Solar*Rewards® program is not included (approximately 432 million KWh for 2018).

Energy Source Statistics

	Xcel Energy	NSP System	PSCo	SPS
2018				
Owned Generation	67%	77%	70%	49%
Purchased Generation	33	23	30	51
	100%	100%	100%	100%
2017				
Owned Generation	66%	75%	70%	47%
Purchased Generation	34	25	30	53
	100%	100%	100%	100%

Renewable Sources

Xcel Energy's renewable energy portfolio includes wind, hydroelectric, biomass and solar power from both owned generating facilities and PPAs. As of Dec. 31, 2018, each utility or system was in compliance with their applicable RPS. Renewable percentages will vary year over year based on local weather, system demand and transmission constraints.

NSP System

Renewable energy as a percentage of the NSP System's total:

	2018	2017
Wind	16.4%	18.3%
Hydroelectric	5.8	6.3
Biomass and solar	4.8	4.2
Renewable	27.0%	28.8%

Wind — The NSP System has more than 130 PPAs ranging from under one MW to more than 200 MW. The NSP System owns and operates five wind farms with 840 MW, net, of capacity.

- The NSP System had approximately 2,550 MW and 2,600 MW of wind energy on its system at the end of 2018 and 2017, respectively.
- Average cost per MWh of wind energy under existing PPAs was approximately $44 for 2018 and 2017.
- Average cost per MWh of wind energy from owned generation was approximately $37 and $42 for 2018 and 2017, respectively.

PSCo

Renewable energy as a percentage of PSCo's total:

	2018	2017
Wind	23.8%	23.7%
Hydroelectric and solar	3.6	3.9
Renewable	27.4%	27.6%

Wind — PSCo has 19 PPAs ranging from two MW to over 300 MW. PSCo owns and operates the Rush Creek wind farm which has 600 MW, net, of capacity.

- PSCo had approximately 3,160 MW and 2,560 MW of wind energy on its system at the end of 2018 and 2017, respectively.
- Average cost per MWh of wind energy under these contracts was approximately $43 and $42 for 2018 and 2017, respectively.
- Rush Creek became operational in December 2018. The 2019 average cost per MWh is expected to be $29.

SPS

Renewable energy as a percentage of SPS' total:

	2018	2017
Wind	19.1%	21.2%
Solar	2.0	2.8
Renewable	21.1%	24.0%

Wind — SPS has 18 PPAs with facilities ranging from under one MW to 250 MW.

- SPS had approximately 1,565 MW and 1,500 MW of wind energy on its system at the end of 2018 and 2017, respectively.
- Average cost per MWh of wind energy under the IPP contracts and QF tariffs was approximately $26 and $27 for 2018 and 2017, respectively.
- In 2018, SPS began construction on the Sagamore and Hale County wind farms. Refer to the SPS Wind Development section for further information.

Non-Renewable Sources

Delivered cost per MMBtu of each significant category of fuel consumed for owned electric generation and the percentage of total fuel requirements represented by each category of fuel:

	Coal (a)		Nuclear		Natural Gas	
	Cost	Percent	Cost	Percent	Cost	Percent
NSP System						
2018	$ 2.13	42%	$ 0.80	45%	$ 3.87	13%
2017	2.08	45	0.78	45	4.10	10
PSCo						
2018	1.45	62	—	—	3.74	38
2017	1.56	70	—	—	3.82	30
SPS						
2018	2.04	56	—	—	2.24	44
2017	2.18	74	—	—	3.39	26

(a) Includes refuse-derived fuel and wood for the NSP System.

Weighted average cost per MMBtu of all fuels for owned electric generation:

	NSP System	PSCo	SPS
2018	$ 1.78	$ 2.33	$ 2.13
2017	1.72	2.25	2.50

See Items 1A and 7 for further information.

Coal — Inventory maintained (in days):

	Normal	Dec. 31, 2018 Actual	Dec. 31, 2017 Actual (a)
NSP System	35 - 50	47	53
PSCo	35 - 50	48	48
SPS	35 - 50	44	52

(a) Milder weather, purchase commitments and low power and natural gas prices impacted coal inventory levels.

Coal requirements (in million tons):

	2018	2017
NSP System	7.8	8.0
PSCo	9.4	10.0
SPS	5.1	5.5

Coal supply as a percentage of requirements (in million tons) for 2019:

	Contracted Coal Supply		2019 Estimated Requirements
NSP System (a)	76%	(b)	8.4
PSCo (a)	83		8.4
SPS (a)	64		4.1

(a) The general coal purchasing objective is to contract for approximately 75% of first year requirements, 40% of year two requirements and 20% of year three requirements.

(b) Increase in estimated million tons was due to lower delivered coal prices at Sherco in January 2019, combined with higher future forecasted gas prices for 2019 (higher burn forecast).

Contracted coal transportation as a percentage of requirements in 2019 and 2020:

	2019	2020
NSP System	100%	100%
PSCo	100	100
SPS	100	100

Natural Gas — Natural gas supplies, transportation and storage services for power plants are procured to provide an adequate supply of fuel. Remaining requirements are procured through a liquid spot market. Generally, natural gas supply contracts have variable pricing that is tied to natural gas indices. Natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified volumes or payments in lieu of delivery.

Contracts and commitments at Dec. 31:

	NSP System		PSCo		SPS	
(Millions of Dollars)	Gas Supply	Gas Transportation and Storage (a)	Gas Supply (b)	Gas Transportation and Storage (a)	Gas Supply	Gas Transportation and Storage (a)
2018	$ —	$ 406	$ 412	$ 589	$ 20	$ 152
2017	—	398	545	620	11	191
Year of Expiration	N/A	2020 - 2037	2021 - 2023	2019 - 2040	One year or less	2019 - 2033

(a) For incremental supplies, there are limited on-site fuel storage facilities, with a primary reliance on the spot market.

(b) Majority of natural gas supply under contract is covered by a long-term agreement with Anadarko Energy Services Company and the balance of natural gas supply contracts have variable pricing features tied to changes in various natural gas indices. PSCo hedges a portion of that risk through financial instruments. See Note 10 to the consolidated financial statements for further information.

Nuclear — NSP-Minnesota secures contracts for uranium concentrates, uranium conversion, uranium enrichment and fuel fabrication to operate its nuclear plants. The contract strategy involves a portfolio of spot purchases and medium and long-term contracts for uranium concentrates, conversion services and enrichment services with multiple producers and with a focus on diversification to minimize potential impacts caused by supply interruptions due to geographical and world political issues.

- Current nuclear fuel supply contracts cover 100% of uranium concentrates requirements through 2021 and approximately 51% of the requirements for 2022 - 2033.
- Current contracts for conversion services cover 100% of the requirements through 2021 and approximately 43% of the requirements for 2022 - 2033.
- Current enrichment service contracts cover 100% of the requirements through 2025 and approximately 19% of the requirements for 2026 - 2033.

Fabrication services for Monticello and PI are 100% committed through 2030 and 2027, respectively.

NSP-Minnesota expects sufficient uranium concentrates, conversion services and enrichment services to be available for the requirements of its nuclear generating plants. Some exposure to market price volatility will remain due to index-based pricing structures contained in supply contracts.

See Item 7 for further information.

Capacity and Demand

Uninterrupted system peak demand and date for the regulated utilities:

	System Peak Demand (in MW)			
	2018		2017	
NSP System [(a)]	8,927	June 29	8,546	July 17
PSCo [(a)]	6,718	July 10	6,671	July 19
SPS [(a)]	4,648	July 19	4,374	July 26

(a) Peak demand typically occurs in the summer. The increase in peak load from 2017 to 2018 is partly due to warmer weather in 2018.

NSP-Minnesota

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — Retail rates, services and other aspects of NSP-Minnesota's operations are regulated by the MPUC, NDPSC and SDPUC. The MPUC also has regulatory authority over security issuances, certain property transfers, mergers, dispositions of assets and transactions between NSP-Minnesota and its affiliates. In addition, the MPUC reviews and approves NSP-Minnesota's IRPs for meeting future energy needs. In addition, MPUC certifies the need and siting for generating plants greater than 50 MW and transmission lines greater than 100 KV that will be located within the state. The NDPSC and SDPUC have regulatory authority over generation and transmission facilities, along with the siting and routing of new generation and transmission facilities in North Dakota and South Dakota, respectively.

NSP-Minnesota is subject to the jurisdiction of the FERC for its wholesale electric operations, hydroelectric licensing, accounting practices, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transfers and mergers, and natural gas transactions in interstate commerce.

NSP-Minnesota is a transmission owning member of the MISO RTO and operates within the MISO RTO and MISO wholesale markets. NSP-Minnesota makes wholesale sales in other RTO markets at market-based rates. NSP-Minnesota and NSP-Wisconsin also make wholesale electric sales at market-based prices to customers outside of their balancing authority as jointly authorized by the FERC.

Fuel, Purchased Energy and Conservation Cost-Recovery Mechanisms —

- *CIP rider* — Recovers the costs of conservation and demand-side management programs.
- *EIR* — Recovers the costs of environmental improvement projects.
- *RDF* — Allocates money collected from retail customers to support the research and development of emerging renewable energy projects and technologies.
- *RES* — Recovers the cost of renewable generation in Minnesota.
- *RER* — Recovers the cost of renewable generation located in North Dakota.
- *SEP* — Recovers costs related to various energy policies approved by the Minnesota legislature.
- *TCR* — Recovers costs associated with investments in electric transmission and distribution grid modernization costs.
- *Infrastructure rider* — Recovers costs for investments in generation and incremental property taxes in South Dakota.

NSP-Minnesota's retail electric rates in Minnesota, North Dakota and South Dakota include a FCA for monthly billing adjustments to recover changes in prudently incurred costs of fuel related items and purchased energy. Capacity costs are recovered through base rates and are not recovered through the FCA. Costs associated with MISO are generally recovered through either the FCA or base rates.

In 2017, the MPUC voted to change the FCA process in Minnesota. Under the new process, each month utilities would collect amounts equal to the baseline cost of energy set at the start of the plan year (base would be reset annually). Monthly variations to the baseline costs would be tracked and netted over a 12-month period. Utilities would issue refunds above the baseline costs, and could seek recovery of any overage. Recently, the MPUC delayed implementation until January 2020.

Minnesota state law requires NSP-Minnesota to invest 2% of its state electric revenues and 0.5% of its state gas revenues in CIP. These costs are recovered through an annual cost-recovery mechanism for electric conservation and energy management program expenditures.

Energy Sources and Transmission Service Provider

NSP-Minnesota expects to use power plants, power purchases, CIP/DSM options, new generation facilities and expansion of power plants to meet its system capacity requirements.

Purchased Power — NSP-Minnesota has contracts to purchase power from other utilities and IPPs. Long-term purchased power contracts for dispatchable resources typically require a capacity charge and an energy charge. NSP-Minnesota makes short-term purchases to meet system requirements, replace company owned generation, meet operating reserve obligations or obtain energy at a lower cost.

Purchased Transmission Services — NSP-Minnesota and NSP-Wisconsin have contracts with MISO and other regional transmission service providers to deliver power and energy to their customers.

Wind Development — In 2017, the MPUC approved NSP-Minnesota's proposal to add 1,550 MW of new wind generation including ownership of 1,150 MW of wind generation.

In April 2018, the MPUC approved NSP-Minnesota's petition to build and own the Dakota Range, a 300 MW wind project in South Dakota. NSP-Minnesota's capital investment for the Dakota Range is expected to be approximately $350 million and placed in service in 2021.

In December 2018, the NDPSC approved a settlement agreement for these wind development projects.

PPA Terminations and Amendments — In June 2018, NSP-Minnesota terminated the Benson and Laurentian PPAs, and purchased the Benson biomass facility. As a result, a $103 million regulatory asset was recognized for the costs of the Benson transaction. For Laurentian, a regulatory asset of $109 million was recognized for annual termination payments/obligations. Regulatory approvals provide for recovery of the Benson regulatory asset over 10 years and Laurentian termination payments as they occur (over six years). Termination of the PPAs is expected to save customers over $600 million throughout the next 10 years.

Jurisdictional Cost Recovery Allocation — In December 2016, NSP-Minnesota filed a resource treatment framework with the NDPSC and MPUC. The filing proposed a framework to allow NSP-Minnesota's operations in North Dakota and Minnesota to gradually become more independent of one another with respect to future generation resource selection while also identifying a path for cost sharing of current resources. NSP-Minnesota's filing identified two options: a legal separation, creating a separate North Dakota operating company; or a pseudo-separation, which maintains the current corporate structure but directly assigns the costs and benefits of each resource to the jurisdiction that supports it. Docket remains under consideration by the NDPSC.

Minnesota State ROFR Statute Complaint — In September 2017, LSP Transmission filed a complaint in the Minnesota District Court against the Minnesota Attorney General, MPUC and DOC. The complaint was in response to MISO assigning NSP-Minnesota and ITC Midwest, LLC to jointly own a new 345 KV transmission line from near Mankato, Minnesota to Winnebago, Minnesota. The project was estimated by MISO to cost $108 million and was assigned to NSP-Minnesota and ITC Midwest as the incumbent utilities, consistent with a Minnesota state ROFR statute. The complaint challenged the constitutionality of the state ROFR statute and is seeking declaratory judgment that the statute violates the Commerce Clause of the U.S. Constitution and should not be enforced. The Minnesota state agencies and NSP-Minnesota filed motions to dismiss. In June 2018, the Minnesota District Court granted the defendants' motions to dismiss with prejudice. LSP Transmission filed an appeal in July 2018. It is uncertain when a decision will be rendered.

Nuclear Power Operations and Waste Disposal

NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the PI plant. Nuclear power plant operations produce gaseous, liquid and solid radioactive wastes which are controlled by federal regulation. High-level radioactive wastes primarily include used nuclear fuel. LLW consists primarily of demineralizer resins, paper, protective clothing, rags, tools and equipment that have become contaminated through use in a plant.

NRC Regulation — The NRC regulates nuclear operations. Costs of complying with NRC requirements can affect both operating expenses and capital investments of the plants. NSP-Minnesota has obtained recovery of these compliance costs in customer rates and expects future compliance costs will continue to be recoverable.

LLW Disposal — LLW from NSP-Minnesota's Monticello and PI nuclear plants is currently disposed at the Clive facility located in Utah and the Waste Control Specialists facility located in Texas. If off-site LLW disposal facilities become unavailable, NSP-Minnesota has storage capacity available on-site at PI and Monticello which would allow both plants to continue to operate until the end of their current licensed lives.

High-Level Radioactive Waste Disposal — The federal government has responsibility to permanently dispose domestic spent nuclear fuel and other high-level radioactive wastes. The Nuclear Waste Policy Act requires the DOE to implement a program for nuclear high-level waste management. This includes the siting, licensing, construction and operation of a repository for spent nuclear fuel from civilian nuclear power reactors and other high-level radioactive wastes at a permanent federal storage or disposal facility. The federal government has been evaluating a nuclear geologic repository at Yucca Mountain, Nevada for many years. Currently, there are no definitive plans for a permanent federal storage facility at Yucca Mountain or any other site.

Review of PI Costs — As part of NSP-Minnesota's 2016 multi-year electric rate case and IRP, the MPUC ordered an investigation into NSP-Minnesota's PI nuclear investments. The issue was resolved as part of the 2016 multi-year electric rate case settlement. In November 2018, the DOC issued a final report, in which no cost disallowances were recommended.

Nuclear Spent Fuel Storage — NSP-Minnesota has interim on-site storage for spent nuclear fuel at its Monticello and PI nuclear generating plants. Authorized storage capacity is sufficient to allow NSP-Minnesota to operate until the end of the operating licenses in 2030 for Monticello, 2033 for PI Unit 1, and 2034 for PI Unit 2. Authorizations for additional spent fuel storage capacity may be required at each site to support either continued operation or decommissioning if the federal government does not commence storage operations.

In 2013, NSP-Minnesota's Monticello nuclear generating plant loaded and placed five storage canisters (canisters #11-15) in the ISFSI and a sixth canister (canister #16) was loaded but remained in the plant pending resolution of weld inspection issues. Successful pressure and leak testing demonstrated the safety and integrity of all six canisters involved. NSP-Minnesota took several actions to assure compliance with the NRC's regulations and Monticello's storage license. The NRC has approved NSP-Minnesota's compliance plan for all canisters.

NSP-Minnesota intends to seek recovery of these costs in a future regulatory proceeding. No public safety issues have been raised, or are believed to exist, in this matter.

See Note 12 to the consolidated financial statements for further information.

Wholesale and Commodity Marketing Operations

NSP-Minnesota conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy, ancillary services and energy-related products. NSP-Minnesota uses physical and financial instruments to minimize commodity price and credit risk and hedge sales and purchases. NSP-Minnesota also engages in trading activity unrelated to hedging and sharing of any margins is determined through state regulatory proceedings as well as the operation of the FERC approved JOA. NSP-Minnesota does not serve any wholesale requirements customers at cost-based regulated rates.

NSP-Wisconsin

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — Retail rates, services and other aspects of NSP-Wisconsin's operations are regulated by the PSCW and the MPSC. In addition, each of the state commissions certifies the need for new generating plants and electric transmission lines before the facilities may be sited and built. NSP-Wisconsin is subject to the jurisdiction of the FERC for its wholesale electric operations, hydroelectric generation licensing, accounting practices, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transactions and mergers and natural gas transactions in interstate commerce. NSP-Wisconsin is a transmission owning member of the MISO RTO that operates within the MISO RTO and wholesale energy market. NSP-Wisconsin and NSP-Minnesota are jointly authorized by the FERC to make wholesale electric sales at market-based prices.

The PSCW has a biennial base rate filing requirement. By June of each odd numbered year, NSP-Wisconsin must submit a rate filing for the test year beginning the following January.

Fuel and Purchased Energy Cost Recovery Mechanisms — NSP-Wisconsin does not have an automatic electric fuel adjustment clause. Instead, under Wisconsin rules, utilities submit a forward-looking annual fuel cost plan to the PSCW. Once the PSCW approves the fuel cost plan, utilities defer the amount of any fuel cost under-recovery or over-recovery in excess of a 2% annual tolerance band, for future rate recovery or refund. Approval of a fuel cost plan and any rate adjustment for refund or recovery of deferred costs is determined by the PSCW. Rate recovery of deferred fuel cost is subject to an earnings test based on the utility's most recently authorized ROE. Fuel cost under-collections that exceed the 2% annual tolerance band may not be recovered if the utility earnings for that year exceed the authorized ROE.

NSP-Wisconsin's electric fuel costs for 2018 were lower than authorized in rates and outside the 2% annual tolerance band, primarily due to greater than forecasted generation sales into the MISO market and lower purchased power costs coupled with moderate weather. Under the fuel cost recovery rules, NSP-Wisconsin retained approximately $3.6 million of fuel costs and deferred approximately $2.8 million. NSP-Wisconsin will file a reconciliation of 2018 fuel costs with the PSCW by March 31, 2019.

NSP-Wisconsin's retail electric rate schedules for Michigan customers include power supply cost recovery factors, which are based on 12-month projections. After each 12-month period, a reconciliation is submitted whereby over-recoveries are refunded and any under-recoveries are collected from customers.

Wisconsin Energy Efficiency Program — The primary energy efficiency program is funded by the state's utilities, but operated by independent contractors subject to oversight by the PSCW and utilities. NSP-Wisconsin recovers these costs from retail customers.

Transmission Initiatives

NSP-Wisconsin operates an integrated system with NSP-Minnesota. See NSP-Minnesota-Energy Sources and Transmission Service Provider.

NSP-Wisconsin / American Transmission Company, LLC - La Crosse to Madison, WI Transmission Line — In December 2018, construction was completed on the Badger Coulee 345 KV transmission line. The line extends from La Crosse, WI. to Madison, WI. NSP-Wisconsin's half of the line is shared with Dairyland Power Cooperative, WPPI Energy and Southern Minnesota Municipal Power Agency-Wisconsin.

Wholesale and Commodity Marketing Operations

NSP-Wisconsin does not serve any wholesale requirements customers at cost-based regulated rates.

PSCo

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — PSCo is regulated by the CPUC with respect to its facilities, rates, accounts, services and issuance of securities. PSCo is regulated by the FERC for its wholesale electric operations, accounting practices, hydroelectric licensing, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with the NERC electric reliability standards, asset transactions and mergers and natural gas transactions in interstate commerce. PSCo is not presently a member of an RTO and does not operate within an RTO energy market. However, PSCo does make certain sales to other RTO's, including SPP. PSCo makes wholesale electric sales at cost-based prices to customers inside PSCo's balancing authority area and at market-based prices to customers outside PSCo's balancing authority area as authorized by the FERC.

Fuel, Purchased Energy and Conservation Cost-Recovery Mechanisms

- *ECA* — Recovers fuel and purchased energy costs. Short-term sales margins are shared with retail customers through the ECA. The ECA is revised quarterly.
- *PCCA* — Recovers purchased capacity payments.
- *SCA* — Recovers the difference between PSCo's actual cost of fuel and costs recovered under its steam service rates. The SCA rate is revised quarterly.
- *DSMCA* — Recovers DSM, interruptible service costs and performance initiatives for achieving energy savings goals.
- *RESA* — Recovers the incremental costs of compliance with the RES with a maximum of 2% of the customer's bill.
- *WCA* — Recovers costs for customers who choose renewable resources.
- *TCA* — Recovers costs for transmission investment outside of rate cases.
- *CACJA* — Recovers costs associated with the CACJA.

PSCo recovers fuel and purchased energy costs from its wholesale electric customers through a fuel cost adjustment clause approved by the FERC. Wholesale customers pay their jurisdictional allocation of production costs through a fully forecasted formula rate with true-up.

Energy Sources and Transmission Service Providers

PSCo expects to meet its system capacity requirements through electric generating stations, power purchases, new generation facilities, DSM options and expansion of generation plants.

Purchased Power — PSCo purchases power from other utilities and IPPs. Long-term purchased power contracts for dispatchable resources typically require capacity and energy charges. It also contracts to purchase power for both wind and solar resources. PSCo makes short-term purchases to meet system load and energy requirements, replace owned generation, meet operating reserve obligations, or obtain energy at a lower cost.

Purchased Transmission Services — In addition to using its own transmission system, PSCo has contracts with regional transmission service providers to deliver energy to its customers.

Wind Development — In 2018, PSCo completed construction and placed in service its Rush Creek 600 MW wind farm in Colorado.

CEP — In September 2018, the CPUC approved PSCo's preferred CEP portfolio, which included the retirement of two coal-fired generation units, Comanche Unit 1 (in 2022) and Comanche Unit 2 (in 2025), and the following additions:

	Total Capacity	PSCo's Ownership
Wind generation	1,100 MW	500 MW
Solar generation	700 MW	—
Battery storage	275 MW	—
Natural gas generation	380 MW	380 MW

PSCo's investment is expected to be approximately $1 billion, including transmission to support the increase in renewable generation. This investment includes the 500 MW Cheyenne Ridge wind farm and 345 KV generation tie line, as well as the Shortgrass Substation. CPCNs for these projects were filed in December 2018. A CPUC decision is anticipated by May 2019. CPCNs for the natural gas generation facility are anticipated to be filed by mid-2019.

Boulder Municipalization — In 2011, Boulder passed a ballot measure authorizing the formation of an electric municipal utility, subject to certain conditions. Subsequently, there have been various legal proceedings in multiple venues with jurisdiction over Boulder's plan. In 2014, the Boulder City Council passed an ordinance to establish an electric utility. PSCo challenged the formation of this utility and the Colorado Court of Appeals ruled in PSCo's favor, vacating a lower court decision. In June 2018, the Colorado Supreme court rejected Boulder's request to dismiss the case and remanded it to the Boulder District Court.

Boulder has filed multiple separation applications with the CPUC, which have been challenged by PSCo and other intervenors. In September 2017, the CPUC issued a written decision, agreeing with several key aspects of PSCo's position. The CPUC has approved the designation of some electrical distribution assets for transfer, subject to Boulder completing certain filings. Those filings were submitted in the fourth quarter of 2018. Subsequently, various parties requested the CPUC commence additional processes; the form of such processes is currently under consideration. In the fourth quarter of 2018, Boulder's City Council also adopted an Ordinance authorizing Boulder to begin negotiations for the acquisition of certain property or to otherwise condemn that property after Feb. 1, 2019. In the first quarter of 2019, Boulder sent PSCo a Notice of Intent to acquire certain electric distribution assets.

Boulder does not have authorization from the CPUC to initiate a condemnation proceeding at this time.

Wholesale and Commodity Marketing Operations

PSCo conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy, ancillary services and energy related products. PSCo uses physical and financial instruments to minimize commodity price and credit risk and hedge sales and purchases. PSCo also engages in trading activity unrelated to hedging and sharing of any margins is determined through state regulatory proceedings as well as the operation of the FERC approved JOA.

SPS

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — The PUCT and NMPRC regulate SPS' retail electric operations and have jurisdiction over its retail rates and services and the construction of transmission or generation in their respective states. The municipalities in which SPS operates in Texas have original jurisdiction over SPS' rates in those communities. The municipalities' rate setting decisions are subject to PUCT review.

SPS is regulated by the FERC for its wholesale electric operations, accounting practices, wholesale sales for resale, the transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transactions and mergers, and natural gas transactions in interstate commerce. SPS is a transmission-owning member of the SPP RTO and operates within the SPP RTO and SPP IM wholesale market. SPS is authorized to make wholesale electric sales at market-based prices.

Fuel, Purchased Energy and Conservation Cost-Recovery Mechanisms —

- *DCRF* — Recovers distribution costs not included in rates in Texas.
- *EECRF* — Recovers costs for energy efficiency programs in Texas.
- *EE rider* — Recovers costs for energy efficiency programs in New Mexico.
- *FPPCAC* — Adjusts monthly to recover the actual fuel and purchased power costs in New Mexico.
- *PCRF* — Allows recovery of purchased power costs not included in rates in Texas.
- *RPS* — Recovers deferred costs for renewable energy programs in New Mexico.
- *TCRF* — Recovers certain transmission infrastructure improvement costs and changes in wholesale transmission charges not included in base rates in Texas.

The fixed fuel and purchased energy recovery factor provides for the over- or under-recovery of energy expenses. Regulations require refunding or surcharging over- or under- recovery amounts, including interest, when they exceed 4% of the utility's annual fuel and purchased energy costs on a rolling 12-month basis, if this condition is expected to continue.

SPS recovers fuel and purchased energy costs from its wholesale customers through a monthly wholesale fuel and purchased energy cost adjustment clause accepted by the FERC. Wholesale customers also pay the jurisdictional allocation of production costs.

Energy Sources and Transmission Service Providers

SPS expects to use electric generating stations, power purchases, DSM and new generation options to meet its system capacity requirements. In addition, it has evaluated water supply issues at the Tolk facility, concluding additional resource investment will be required to operate the plant through its existing life. The Ogallala aquifer has depleted more rapidly than expected. SPS installed a horizontal water well that may help delay the need for a more substantial investment solution. As a result of this issue and future environmental rules facing the plant, it sought a decrease to the remaining life of the facility in the 2017 Texas and New Mexico rate case proceedings.

Purchased Power — SPS purchases power from other utilities and IPPs. Long-term purchased power contracts typically require periodic capacity and energy charges. SPS also makes short-term purchases to meet system load and energy requirements to replace owned generation, meet operating reserve obligations or obtain energy at a lower cost.

Purchased Transmission Services — SPS has contractual arrangements with SPP and regional transmission service providers to deliver power and energy to its native load customers.

Wind Development — In 2018, the NMPRC and PUCT approved SPS' proposal to add 1,230 MW of new wind generation, including 1,000 MW ownership.

In March 2018, the NMPRC approved SPS' petition to build and own Sagamore, a 522 MW wind project in New Mexico which is expected to be placed into service in 2020. In May 2018, the PUCT approved SPS' petition to build and own Hale County, a 478 MW wind project in Texas which is expected to be placed into service in 2019. Both projects qualify for 100% of PTCs. SPS' capital investment for these wind projects is expected to be approximately $1.6 billion.

Texas State ROFR Request for Declaratory Order — In 2017, SPS and SPP filed a joint petition with the PUCT for a declaratory order regarding SPS' ROFR. SPS contended that Texas law grants an incumbent electric utility the ROFR to construct new transmission facilities located in the utility's service area. The PUCT subsequently issued an order finding that SPS does not possess an exclusive right to construct and operate transmission facilities. In January 2018, SPS and two other parties filed appeals in the Texas State District Court. In September 2018, the District Court affirmed the PUCT's ROFR order. SPS has filed an additional appeal.

NATURAL GAS UTILITY OPERATIONS

Natural Gas Operating Statistics

	Year Ended Dec. 31		
	2018	2017	2016
Natural gas deliveries (Thousands of MMBtu)			
Residential	149,036	134,189	132,853
C&I	96,447	87,271	84,082
Total retail	245,483	221,460	216,935
Transportation and other	173,092	142,497	133,498
Total deliveries	418,575	363,957	350,433
Number of customers at end of period			
Residential	1,878,576	1,856,221	1,835,507
C&I	158,424	157,798	157,286
Total retail	2,037,000	2,014,019	1,992,793
Transportation and other	7,951	7,705	7,316
Total customers	2,044,951	2,021,724	2,000,109
Natural gas revenues (Millions of Dollars)			
Residential	$ 1,045	$ 1,006	$ 930
C&I	556	524	469
Total retail	1,601	1,530	1,399
Transportation and other	138	120	132
Total natural gas revenues	$ 1,739	$ 1,650	$ 1,531
MMBtu sales per retail customer	120.51	109.96	108.86
Revenue per retail customer	$ 786	$ 760	$ 702
Residential revenue per MMBtu	7.01	7.50	7.00
C&I revenue per MMBtu	5.76	6.00	5.58
Transportation and other revenue per MMBtu	0.80	0.84	0.99

Capability and Demand

Natural gas supply requirements are categorized as firm or interruptible (customers with an alternate energy supply).

Maximum daily send-out (firm and interruptible) and occurrence date:

	2018		2017	
Utility Subsidiary	MMBtu	Date	MMBtu	Date
NSP-Minnesota	786,751 (a)	Jan. 12	893,062	Dec. 26
NSP-Wisconsin	159,700	Jan. 5	160,170	Dec. 26
PSCo	1,903,878 (a)	Feb. 20	1,948,167	Jan. 5

(a) Decrease in MMBtu output due to milder winter temperatures in 2018.

Natural gas is purchased from independent suppliers, generally based on market indices that reflect current prices, and is delivered under transportation agreements with interstate pipelines.

Contracted firm deliverable pipeline capacity as of Dec. 31:

Utility Subsidiary	MMBtu Per Day
NSP-Minnesota	645,171
NSP-Wisconsin	140,195
PSCo	1,834,843 (a)

(a) Includes 871,418 MMBtu of natural gas under third-party underground storage agreements.

The utility subsidiaries contract with providers of underground natural gas storage services. Agreements provided storage of winter natural gas and peak day firm requirements for 2018 as follows:

Utility Subsidiary	Percent of Winter Requirements	Peak Day Firm Requirements
NSP-Minnesota	24%	29%
NSP-Wisconsin	30	33

PSCo also operates three company-owned underground storage facilities, which provide approximately 43,500 MMBtu of natural gas on peak days. The balance required to meet firm peak day sales obligations is primarily purchased at PSCo's city gate meter stations.

Natural Gas Supply and Costs

Xcel Energy actively seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio which provides increased flexibility, decreased interruption and financial risk and economical rates. In addition, the utility subsidiaries conduct natural gas price hedging activities approved by their respective state commissions.

Average delivered cost per MMBtu of natural gas for regulated retail distribution:

	NSP-Minnesota	NSP-Wisconsin	PSCo
2018	$ 4.03	$ 3.84	$ 3.20
2017	3.89	3.88	3.45

NSP-Minnesota, NSP-Wisconsin and PSCo have natural gas supply transportation and storage agreements that include obligations for purchase and/or delivery of specified volumes or to make payments in lieu of delivery. As of Dec. 31, 2018, the utility subsidiaries had the following contractual obligations:

- NSP-Minnesota — $437 million (expire 2019 - 2033);
- NSP-Wisconsin — $89 million (expire 2019 - 2029); and,
- PSCo — $1.1 billion (expire 2019 - 2029).

NSP-Minnesota

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — Retail rates, services and other aspects of NSP-Minnesota's retail natural gas operations are regulated by the MPUC and NDPSC. The MPUC has regulatory authority over security issuances, certain property transfers, mergers with other utilities and transactions between NSP-Minnesota and its affiliates. The MPUC reviews and approves NSP-Minnesota's natural gas supply plans for meeting future energy needs. NSP-Minnesota is subject to the jurisdiction of the FERC with respect to certain natural gas transactions in interstate commerce. NSP-Minnesota is also subject to the DOT, Minnesota Office of Pipeline Safety, NDPSC and SDPUC for pipeline safety compliance.

Purchased Gas and Conservation Cost-Recovery Mechanisms — NSP-Minnesota's retail natural gas rates for Minnesota and North Dakota include a PGA clause that provides for prospective monthly rate adjustments to reflect the forecasted cost of purchased natural gas, transportation and storage service. The annual difference between the natural gas cost revenues collected through PGA rates and the actual natural gas costs is collected or refunded over the subsequent 12-month period.

NSP-Minnesota also recovers costs associated with transmission and distribution pipeline integrity management programs through its GUIC rider. Costs recoverable under the GUIC rider include funding for pipeline assessments as well as deferred costs from NSP-Minnesota's existing sewer separation and pipeline integrity management programs.

NSP-Wisconsin

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — NSP-Wisconsin is regulated by the PSCW and MPSC. The PSCW has a biennial base-rate filing requirement. By June of each odd-numbered year, NSP-Wisconsin must submit a rate filing for the test year period beginning the following January.

NSP-Wisconsin is subject to the jurisdiction of the FERC with respect to natural gas transactions in interstate commerce. NSP-Wisconsin is subject to the DOT, PSCW and MPSC for pipeline safety compliance.

Natural Gas Cost-Recovery Mechanisms — NSP-Wisconsin has a retail PGA cost-recovery mechanism for Wisconsin to recover the actual cost of natural gas and transportation and storage services.

NSP-Wisconsin's natural gas rates for Michigan customers include a natural gas cost-recovery factor, which is based on 12-month projections and trued-up to actual amounts on an annual basis.

PSCo

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — PSCo is regulated by the CPUC with respect to its facilities, rates, accounts, services and issuance of securities. PSCo holds a FERC certificate that allows it to transport natural gas in interstate commerce without PSCo becoming subject to full FERC jurisdiction. PSCo is subject to the DOT and CPUC with regards to pipeline safety compliance.

Purchased Natural Gas and Conservation Cost-Recovery Mechanisms

- *GCA* — Recovers the costs of purchased natural gas and transportation to meet customer requirements and is revised quarterly to allow for changes in natural gas rates.
- *DSMCA* — Recovers costs of DSM and performance initiatives to achieve various energy savings goals.
- *PSIA* — Recovers costs for transmission and distribution pipeline integrity management programs.

SPS

Natural Gas Facilities Used for Electric Generation

SPS does not provide retail natural gas service, but purchases and transports natural gas for its generation facilities and operates natural gas pipeline facilities connecting the generation facilities to interstate natural gas pipelines. SPS is subject to the jurisdiction of the FERC with respect to natural gas transactions in interstate commerce and the PHMSA and PUCT for pipeline safety compliance.

GENERAL

Seasonality

Demand for electric power and natural gas is affected by seasonal differences in the weather. In general, peak sales of electricity occur in the summer months and peak sales of natural gas occur in the winter months. As a result, the overall operating results may fluctuate substantially on a seasonal basis. Additionally, Xcel Energy's operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer.

See Item 7 for further information.

Competition

Xcel Energy is a vertically integrated utility subject to traditional cost-of-service regulation by state public utilities commissions. Xcel Energy is subject to public policies that promote competition and development of energy markets. Xcel Energy's industrial and large commercial customers have the ability to generate their own electricity. In addition, customers may have the option of substituting other fuels or relocating their facilities to a lower cost region.

Customers have the opportunity to supply their own power with distributed generation including, but not limited to, solar generation and in most jurisdictions can currently avoid paying for most of the fixed production, transmission and distribution costs incurred to serve them. Several states have policies designed to promote the development of solar and other distributed energy resources through incentive policies. With these incentives and federal tax subsidies, distributed generating resources are potential competitors to Xcel Energy's electric service business.

The FERC has continued to promote competitive wholesale markets through open access transmission and other means. As a result, Xcel Energy Inc.'s utility subsidiaries and their wholesale customers can purchase the output from generation resources of competing wholesale suppliers and use the transmission systems of the utility subsidiaries on a comparable basis to serve their native load.

FERC Order No. 1000 seeks to establish competition for construction and operation of certain new electric transmission facilities. State utilities commissions have also created resource planning programs that promote competition for electricity generation resources used to provide service to retail customers.

Xcel Energy Inc.'s utility subsidiaries have franchise agreements with cities subject to periodic renewal, however, a city could seek alternative means to access electric power or gas, such as municipalization.

While each of Xcel Energy Inc.'s utility subsidiaries faces these challenges, Xcel Energy believes their rates and services are competitive with the alternatives currently available.

ENVIRONMENTAL MATTERS

Xcel Energy's facilities are regulated by federal and state environmental agencies that have jurisdiction over air emissions, water quality, wastewater discharges, solid wastes and hazardous substances. Various company activities require registrations, permits, licenses, inspections and approvals from these agencies. Xcel Energy has received all necessary authorizations for the construction and continued operation of its generation, transmission and distribution systems. Xcel Energy's facilities have been designed and constructed to operate in compliance with applicable environmental standards and related monitoring and reporting requirements. However, it is not possible to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of changes to environmental regulations, interpretations or enforcement policies or what effect future laws or regulations may have upon Xcel Energy's operations. Xcel Energy will likely be required to incur capital expenditures in the future to comply with requirements for remediation of MGP and other legacy sites. The scope and timing of these expenditures cannot be determined until more information is obtained regarding the need for remediation at legacy sites.

In Minnesota, Texas and Wisconsin, Xcel Energy must comply with emission budgets that require the purchase of emission allowances from other utilities. The Denver North Front Range Nonattainment Area does not meet either the 2008 or 2015 ozone NAAQS. Colorado will continue to consider further reductions available in the non-attainment area as it develops plans to meet ozone standards. Gas plants which operate in PSCo's non-attainment area may be required to improve or add controls, implement further work practices and/or implement enhanced emissions monitoring as part of future Colorado state plans.

There are significant present and future environmental regulations to encourage use of clean energy technologies and regulate emissions of GHGs. Xcel Energy has undertaken numerous initiatives to meet current requirements and prepare for potential future regulations, reduce GHG emissions and respond to state renewable and energy efficiency goals. If future environmental regulations do not provide credit for the investments Xcel Energy has already made or if they require additional initiatives or emission reductions, substantial costs may be incurred. The EPA, as an alternative to the CPP, has proposed a new regulation that, if adopted, would require implementation of heat rate improvement projects at our coal-fired power plants. It is not known what those costs might be until a final rule is adopted and state plans are developed to implement a final regulation. Xcel Energy believes, based on prior state commission practice, the cost of these initiatives or replacement generation would be recoverable through rates.

Xcel Energy is committed to addressing climate change and potential climate change regulation through efforts to reduce its GHG emissions in a balanced, cost-effective manner. Starting in 2011, Xcel Energy began reporting GHG emissions under the EPA's mandatory GHG Reporting Program.

Xcel Energy estimates that in 2018, it reduced the CO_2 emissions associated with the electric generating resources used to serve its customers by approximately 40% from 2005 levels. This reduction accounts for emissions from electric generating plants owned by Xcel Energy as well as purchased power.

Xcel Energy primarily relied on strategies that resulted in:

- Development of renewable energy facilities;
- Retirement and replacement of existing generating plants; and,
- Customer energy efficiency programs.

CAPITAL SPENDING AND FINANCING

See Item 7 for a discussion of expected capital expenditures and funding sources.

EMPLOYEES

As of Dec. 31, 2018, Xcel Energy had 11,043 full-time employees and 49 part-time employees, of which 5,129 were covered under CBAs.

	Employees Covered by CBAs	Total Employees
NSP-Minnesota	2,064	3,278
NSP-Wisconsin	386	540
PSCo	1,904	2,426
SPS	775	1,151
XES	—	3,697
Total	5,129	11,092

EXECUTIVE OFFICERS [(a)]

Name	Age [(b)]	Current and Recent Positions Held	Time in Position
Ben Fowke	60	Chairman of the Board, President and Chief Executive Officer and Director, Xcel Energy Inc.	August 2011 - Present
		Chief Executive Officer, NSP-Minnesota, NSP-Wisconsin, PSCo, and SPS	January 2015 - Present
Brett C. Carter	52	Executive Vice President and Chief Customer and Innovation Officer, Xcel Energy Inc.	May 2018 - Present
		Senior Vice President and Shared Services Executive, Bank of America	October 2015 - May 2018
		Senior Vice President and Chief Operating Officer, Bank of America	March 2015 - October 2015
		Senior Vice President and Chief Distribution Officer, Duke Energy Co.	February 2013 - March 2015
Christopher B. Clark	52	President and Director, NSP-Minnesota	January 2015 - Present
		Regional Vice President, Rates and Regulatory Affairs, NSP-Minnesota	October 2012 - December 2014
David L. Eves	60	Executive Vice President and Group President, Utilities, Xcel Energy Inc.	March 2018 - Present
		President and Director, PSCo	January 2015 - February 2018
		President, Director and Chief Executive Officer, PSCo	December 2009 - December 2014
Darla Figoli	56	Senior Vice President, Human Resources & Employee Services, Chief Human Resources Officer, Xcel Energy Inc.	May 2018 - Present
		Senior Vice President, Human Resources and Employee Services, Xcel Energy Inc.	May 2015 - May 2018
		Vice President, Human Resources, Xcel Energy Inc.	February 2010 - May 2015
Robert C. Frenzel	48	Executive Vice President, Chief Financial Officer, Xcel Energy Inc.	May 2016 - Present
		Senior Vice President and Chief Financial Officer, Luminant, a subsidiary of Energy Future Holdings Corp. [(c)]	February 2012 - April 2016
David T. Hudson	58	President and Director, SPS	January 2015 - Present
		President, Director and Chief Executive Officer, SPS	January 2014 - December 2014
Alice Jackson	40	President and Director, PSCo	May 2018 - Present
		Area Vice President, Strategic Revenue Initiatives, Xcel Energy Services Inc.	November 2016 - May 2018
		Regional Vice President, Rates and Regulatory Affairs, PSCo	October 2011 - November 2016
Kent T. Larson	59	Executive Vice President and Group President Operations, Xcel Energy Inc.	January 2015 - Present
		Senior Vice President, Group President Operations, Xcel Energy Services Inc.	August 2014 - December 2014
		Senior Vice President Operations, Xcel Energy Services Inc.	September 2011 - August 2014
Timothy O'Connor	59	Senior Vice President, Chief Nuclear Officer, Xcel Energy Services Inc.	February 2013 - Present
Judy M. Poferl	59	Senior Vice President, Corporate Secretary and Executive Services, Xcel Energy Inc.	January 2015 - Present
		Vice President, Corporate Secretary, Xcel Energy Inc.	May 2013 - December 2014
Jeffrey S. Savage	47	Senior Vice President, Controller, Xcel Energy Inc.	January 2015 - Present
		Vice President, Controller, Xcel Energy Inc.	September 2011 - December 2014
Mark E. Stoering	58	President and Director, NSP-Wisconsin	January 2015 - Present
		President, Director and Chief Executive Officer, NSP-Wisconsin	January 2012 - December 2014
Scott M. Wilensky	62	Executive Vice President, General Counsel, Xcel Energy Inc.	January 2015 - Present
		Senior Vice President, General Counsel, Xcel Energy Inc.	September 2011 - December 2014

(a) No family relationships exist between any of the executive officers or directors.

(b) Ages as of Dec. 31, 2018.

(c) In April 2014, Energy Future Holdings Corp., the majority of its subsidiaries, including TCEH the parent company of Luminant, filed a voluntary bankruptcy petition. TCEH emerged from Chapter 11 in October 2016.

Item 1A — Risk Factors

Xcel Energy is subject to a variety of risks, many of which are beyond our control. Risks that may adversely affect the business, financial condition, results of operations or cash flows are described below. These risks should be carefully considered together with the other information set forth in this report and future reports that Xcel Energy files with the SEC.

Oversight of Risk and Related Processes

A key accountability of the Board of Directors is the oversight of material risk, and our Board of Directors employs an effective process for doing so. Management and each Board of Directors' committee have responsibility for overseeing the identification and mitigation of key risks and reporting its assessments and activities to the full Board of Directors.

Management identifies and analyzes risks to determine materiality and other attributes such as timing, probability and controllability. Identification and analysis occurs formally through a key risk assessment conducted by senior management, the financial disclosure process, hazard risk management procedures and internal auditing and compliance with financial and operational controls. Management also identifies and analyzes risk through its business planning process and development of goals and key performance indicators, which include risk identification to determine barriers to implementing Xcel Energy's strategy. The business planning process also identifies areas in which there is a potential for a business area to assume inappropriate risk to meet goals and determines how to prevent inappropriate risk-taking.

Xcel Energy has a robust compliance program and promotes a culture of compliance, including tone at the top. The process for risk mitigation includes adherence to our code of conduct and compliance policies, operation of formal risk management structures and overall business management to mitigate the risks inherent in the implementation of strategy. Xcel Energy manages and further mitigates risks through formal risk management structures, including management councils, risk committees and services of corporate areas such as internal audit, corporate controller and legal.

Management communicates regularly with the Board of Directors and key stakeholders regarding risk. Senior management presents and communicates a periodic risk assessment to the Board of Directors which provides information on the risks management believes are material, including the earnings impact, timing, likelihood and controllability.

The Board of Directors approaches oversight, management and mitigation of risk as an integral and continuous part of its governance of Xcel Energy. The Board of Directors regularly reviews management's key risk assessment and analyzes areas of existing and future risks and opportunities. In addition, the Board of Directors assigns oversight of critical risks to its four committees to ensure these risks are well understood and given appropriate focus. The Audit Committee is responsible for reviewing the adequacy of risk oversight and affirming that appropriate oversight occurs. Oversight of cybersecurity risks by the Operations, Nuclear, Environmental and Safety Committee includes receiving independent outside assessments of cybersecurity maturity and assessment of plans.

New risks are considered and assigned as appropriate during the annual Board of Directors' and committee evaluation process. Committee charters and annual work plans are updated accordingly. Committees regularly report on their oversight activities and certain risk issues may be brought to the full Board of Directors for consideration when deemed appropriate. Finally, the Board of Directors conducts an annual strategy session where Xcel Energy's future plans and initiatives are reviewed.

Risks Associated with Our Business

Operational Risks

Our natural gas and electric transmission and distribution operations involve numerous risks that may result in accidents and other operating risks and costs.

Our natural gas transmission and distribution activities include inherent hazards and operating risks, such as leaks, explosions, outages and mechanical problems. Our electric transmission and distribution activities also include inherent hazards and operating risks such as contact, fire and outages which could cause substantial financial losses. These natural gas and electric risks could result in loss of life, significant property damage, environmental pollution, impairment of our operations and substantial losses. We maintain insurance against some, but not all, of these risks and losses. The occurrence of these events, if not fully covered by insurance, could have a material effect on our financial condition, results of operations and cash flows.

Additionally, for natural gas costs that may be required in order to comply with potential new regulations, including the Pipeline Safety Act, could be significant.

The Pipeline Safety Act requires verification of pipeline infrastructure records by pipeline owners and operators to confirm the maximum allowable operating pressure of lines located in high consequence areas or more-densely populated areas. We have programs in place to comply with the Pipeline Safety Act and for systematic infrastructure monitoring and renewal over time. A significant incident could increase regulatory scrutiny and result in penalties and higher costs of operations.

The PHMSA is responsible for administering the DOT's national regulatory program to assure the safe transportation of natural gas, petroleum and other hazardous materials by pipelines. The PHMSA continues to develop regulations and other approaches to risk management to assure safety in design, construction, testing, operation, maintenance and emergency response of natural gas pipeline infrastructure.

Our utility operations are subject to long-term planning risks.

Most electric utility investments are planned to be used for decades. Transmission and generation investments typically have long lead times and are planned well in advance of when they are brought in-service subject to long-term resource plans. These plans are based on numerous assumptions such as: sales growth, customer usage, commodity prices, economic activity, costs, regulatory mechanisms, customer behavior, available technology and public policy.

The electric utility sector is undergoing a period of significant change. For example, increases in appliance, lighting and energy efficiency, wider adoption and lower cost of renewable generation and distributed generation, shifts away from coal generation to decrease CO_2 emissions and increasing use of natural gas in electric generation driven by lower natural gas prices. Customer adoption of these technologies and increased energy efficiency could result in excess transmission and generation resources as well as stranded costs if Xcel Energy is not able to fully recover the costs and investments. These changes also introduce additional uncertainty into long-term planning which gives rise to a risk that the magnitude and timing of resource additions and growth in customer demand may not coincide and that the preference for the types of additions may change from planning to execution. In addition, we are subject to longer-term availability of the natural resource inputs such as coal, natural gas, uranium and water to cool our facilities. Lack of availability of these resources could jeopardize long-term operations of our facilities or make them uneconomic to operate.

Changing customer expectations and technologies are requiring significant investments in advanced grid infrastructure. This increases the exposure to potential outdating of technologies and resultant risks. The inability of coal mining companies to attract capital could disrupt longer-term supplies. Decreasing use per customer driven by appliance and lighting efficiency and the availability of cost-effective distributed generation places downward pressure on sales growth. This may lead to under recovery of costs, excess resources to meet customer demand and increases in electric rates. Finally, multiple states may not agree as to the appropriate resource mix and the differing views may lead to costs incurred to comply with one jurisdiction that are not recoverable across all of the jurisdictions served by the same assets.

Our subsidiary, NSP-Minnesota, is subject to the risks of nuclear generation.

NSP-Minnesota's two nuclear stations, PI and Monticello, subject it to the risks of nuclear generation, which include:

- Risks associated with use of radioactive material in the production of energy, the management, handling, storage and disposal of radioactive materials;
- Limitations on insurance available to cover losses that might arise in connection with nuclear operations, as well as obligations to contribute to an insurance pool in the event of damages at a covered U.S. reactor; and,
- Uncertainties with the technological and financial aspects of decommissioning nuclear plants. For example, assumptions regarding decommissioning costs may change based on economic conditions and changes in the expected life of the asset may cause our funding obligations to change.

The NRC has authority to impose licensing and safety-related requirements for the operation of nuclear generation facilities. The NRC has the authority to impose fines and/or shut down a unit until compliance is achieved. Revised NRC safety requirements could necessitate substantial capital expenditures or an increase in operating expenses. In addition, the Institute for Nuclear Power Operations reviews NSP-Minnesota's nuclear operations and nuclear generation facilities. Compliance with the Institute for Nuclear Power Operations' recommendations could result in substantial capital expenditures or a substantial increase in operating expenses.

If an incident did occur, it could have a material effect on our results of operations, financial condition or cash flows. Furthermore, the non-compliance or the occurrence of a serious incident at other nuclear facilities could result in increased regulation of the industry, which may increase NSP-Minnesota's compliance costs.

NSP-Wisconsin's production and transmission system is operated on an integrated basis with NSP-Minnesota. NSP-Wisconsin may be subject to risks associated with NSP-Minnesota's nuclear generation.

We are subject to commodity risks and other risks associated with energy markets and energy production.

If fuel costs increase, customer demand could decline and bad debt expense may rise, which could have a material impact on our results of operations. While we have fuel clause recovery mechanisms in most of our states, higher fuel costs could significantly impact our results of operations if costs are not recovered. Delays in the timing of the collection of fuel cost recoveries could impact our cash flows. Low fuel costs have a positive impact on sales, however low oil and natural gas prices could negatively impact oil and gas production activities and subsequently our sales volumes and revenue.

A significant disruption in supply could cause us to seek alternative supply services at potentially higher costs or suffer increased liability for unfulfilled contractual obligations. Significantly higher energy or fuel costs relative to sales commitments have a negative impact on our cash flows and potentially result in economic losses. Potential market supply shortages may not be fully resolved through alternative supply sources and could cause disruptions in our ability to provide electric and/or natural gas services to our customers. Failure to provide service due to disruptions may also result in fines, penalties or cost disallowances through the regulatory process.

We also engage in wholesale sales and purchases of electric capacity, energy and energy-related products as well as natural gas. In many markets, emission allowances and/or RECs are also needed to comply with various statutes and commission rulings. As a result we are subject to market supply and commodity price risk. Commodity price changes can affect the value of our commodity trading derivatives. We mark certain derivatives to estimated fair market value on a daily basis. Actual settlements can vary significantly from estimated fair values recorded and significant changes from the assumptions underlying our fair value estimates could cause earnings variability.

Financial Risks

Our profitability depends on the ability of our utility subsidiaries to recover their costs and changes in regulation may impair the ability of our utility subsidiaries to recover costs from their customers.

We are subject to comprehensive regulation by federal and state utility regulatory agencies, including siting and construction of facilities, customer service and the rates that we can charge customers.

The profitability of our utility operations is dependent on our ability to recover the costs of providing energy and utility services and earn a return on our capital investment. Our rates are generally regulated and based on an analysis of the utility's costs incurred in a test year. Our utility subsidiaries are subject to both future and historical test years depending upon the regulatory jurisdiction. Thus, the rates a utility is allowed to charge may or may not match its costs at any given time. Rate regulation is premised on providing an opportunity to earn a reasonable rate of return on invested capital. In a continued low interest rate environment there has been pressure pushing down ROE. There can also be no assurance that our regulatory commissions will judge all the costs of our utility subsidiaries to be prudent, which could result in disallowances, or that the regulatory process will always result in rates that will produce full recovery. Changes in the long-term cost-effectiveness or changes to the operating conditions of our assets may result in early retirements of utility facilities and while regulation typically provides relief for these types of changes, there is no assurance that regulators would allow full recovery of all remaining costs leaving all or a portion of these asset costs stranded. Higher than expected inflation or tariffs may increase costs of construction and operations. Rising fuel costs could increase the risk that our utility subsidiaries will not be able to fully recover their fuel costs from their customers. Furthermore, there could be changes in the regulatory environment that would impair the ability of our utility subsidiaries to recover costs historically collected from their customers, or these factors could cause the operating utilities to exceed commitments made regarding cost caps and result in less than full recovery. Overall, management currently believes prudently incurred costs are recoverable given the existing regulatory mechanisms in place.

Adverse regulatory rulings or the imposition of additional regulations could have an adverse impact on our results of operations and materially affect our ability to meet our financial obligations, including debt payments and the payment of dividends on our common stock.

Any reductions in our credit ratings could increase our financing costs and the cost of maintaining certain contractual relationships.

We cannot be assured that our current ratings or our subsidiaries' ratings will remain in effect, or that a rating will not be lowered or withdrawn by a rating agency. Significant events including disallowance of costs, significantly lower returns on equity or equity ratios or impacts of tax policy changes may impact our cash flows and credit metrics, potentially resulting in a change in our credit ratings. In addition, our credit ratings may change as a result of the differing methodologies or change in the methodologies used by the various rating agencies.

Any downgrade could lead to higher borrowing costs and could impact our ability to access capital markets. Also, our utility subsidiaries may enter into contracts that require the posting of collateral or settlement of applicable contracts if credit ratings fall below investment grade.

We are subject to capital market and interest rate risks.

Utility operations require significant capital investment. As a result, we frequently need to access capital markets. Any disruption in capital markets could have a material impact on our ability to fund our operations. Capital markets are global and impacted by issues and events throughout the world. Capital market disruption events and financial market distress could prevent us from issuing short-term commercial paper, issuing new securities or cause us to issue securities with unfavorable terms and conditions, such as higher interest rates.

Higher interest rates on short-term borrowings with variable interest rates could also have an adverse effect on our operating results. Changes in interest rates may also impact the fair value of the debt securities in the nuclear decommissioning and/or pension funds, as well as our ability to earn a return on short-term investments of excess cash.

We are subject to credit risks.

Credit risk includes the risk that our customers will not pay their bills, which may lead to a reduction in liquidity and an increase in bad debt expense. Credit risk is comprised of numerous factors including the price of products and services provided, the overall economy and local economies in the geographic areas we serve, including local unemployment rates.

Credit risk also includes the risk that various counterparties that owe us money or product will become insolvent and/or breach their obligations. Should the counterparties fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected and incur losses.

We may at times have direct credit exposure in our short-term wholesale and commodity trading activity to financial institutions trading for their own accounts or issuing collateral support on behalf of other counterparties. We may also have some indirect credit exposure due to participation in organized markets, such as CAISO, SPP, PJM, MISO and Electric Reliability Council of Texas, in which any credit losses are socialized to all market participants.

We have additional indirect credit exposures to financial institutions in the form of letters of credit provided as security by power suppliers under various purchased power contracts. If any of the credit ratings of the letter of credit issuers were to drop below investment grade, the supplier would need to replace that security with an acceptable substitute. If the security were not replaced, the party could be in default under the contract.

Increasing costs of our defined benefit retirement plans and employee benefits may adversely affect our results of operations, financial condition or cash flows.

We have defined benefit pension and postretirement plans that cover most of our employees. Assumptions related to future costs, return on investments, interest rates and other actuarial assumptions have a significant impact on our funding requirements related to these plans. Estimates and assumptions may change. In addition, the Pension Protection Act changed the minimum funding requirements for defined benefit pension plans. Therefore, our funding requirements and related contributions may change in the future. Also, the payout of a significant percentage of pension plan liabilities in a single year due to high retirements or employees leaving could trigger settlement accounting and could require Xcel Energy to recognize incremental pension expense related to unrecognized plan losses in the year liabilities are paid.

Increasing costs associated with health care plans may adversely affect our results of operations.

Our self-insured costs of health care benefits for eligible employees have increased in recent years. Increasing levels of large individual health care claims and overall health care claims could have an adverse impact on our results of operations, financial condition or cash flows. Changes in industry standards utilized in key assumptions (e.g., mortality tables) could have a significant impact on future liabilities and benefit costs. Legislation related to health care could also significantly change our benefit programs and costs.

We must rely on cash from our subsidiaries to make dividend payments.

We are a holding company and investments in our subsidiaries are our primary assets. Substantially all of our operations are conducted by our subsidiaries. Consequently, our operating cash flow and ability to service our debt and pay dividends depends upon the operating cash flows of our subsidiaries and their payment of dividends. Our subsidiaries are separate legal entities that have no obligation to pay any amounts due pursuant to our obligations or to make any funds available for dividends on our common stock. In addition, each subsidiary's ability to pay dividends depends on statutory and/or contractual restrictions which may include requirements to maintain minimum levels of equity ratios, working capital or assets. Also, our utility subsidiaries are regulated by state utility commissions, which possess broad powers to ensure that the needs of the utility customers are being met.

If our utility subsidiaries were to cease making dividend payments, our ability to pay dividends on our common stock or otherwise meet our financial obligations could be adversely affected.

Federal tax law may significantly impact our business.

Xcel Energy's utility subsidiaries collect through regulated rates estimated federal, state and local tax payments. Changes to federal tax law may benefit or adversely affect our earnings and customer costs. Changes to tax depreciable lives and the value of various tax credits may change the economics of resources and our resource selections. There could be timing delays before regulated rates provide for realization of the tax changes in revenues. In addition, certain IRS tax policies such as the requirement to utilize normalization may impact our ability to economically deliver certain types of resources relative to market prices.

Macroeconomic Risks

Economic conditions impact our business.

Our operations are affected by local, national and worldwide economic conditions. Growth in customers and sales are correlated with economic conditions.

Economic conditions may be impacted by insufficient financial sector liquidity leading to potential increased unemployment, which may impact customers' ability to pay timely, increase customer bankruptcies, and may lead to additional bad debt expense.

Further, worldwide economic activity impacts the demand for basic commodities necessary for utility infrastructure, which may impact our ability to acquire sufficient supplies. We operate in a capital intensive industry and federal policy on trade could significantly impact the cost of materials we use. We could be at risk for higher costs for materials and our workforce. There may be delays before these additional costs can be recovered in rates.

Our operations could be impacted by war, acts of terrorism, and threats of terrorism or disruptions due to events.

Our generation plants, fuel storage facilities, transmission and distribution facilities and information and control systems may be targets of terrorist activities. Any disruption could impact operations or result in a decrease in revenues and additional costs to repair and insure our assets. These disruptions could have a material impact on our financial condition, results of operations or cash flows. The potential for terrorism has subjected our operations to increased risks and could have a material effect on our business. We have already incurred increased costs for security and capital expenditures in response to these risks.

The insurance industry has also been affected by these events and the availability of insurance may decrease. In addition, insurance may have higher deductibles, higher premiums and more restrictive policy terms.

A disruption of the regional electric transmission grid, interstate natural gas pipeline infrastructure or other fuel sources, could negatively impact our business, our brand and reputation. Because our facilities are part of an interconnected system, we face the risk of possible loss of business due to a disruption caused by the actions of a neighboring utility or an event (e.g., severe storm, severe temperature extremes, wildfires, generator or transmission facility outage, pipeline rupture, railroad disruption, operator error, sudden and significant increase or decrease in wind generation or a disruption of work force) within our operating systems or on a neighboring system. Any such disruption could result in a significant decrease in revenues and significant additional costs to repair assets, which could have a material impact on our results of operations, financial condition or cash flows.

A cyber incident or security breach could have a material effect on our business.

We operate in an industry that requires the continued operation of sophisticated information technology, control systems and network infrastructure. In addition, we use our systems and infrastructure to create, collect, use, disclose, store, dispose of and otherwise process sensitive information, including company data, customer energy usage data, and personal information regarding customers, employees and their dependents, contractors, shareholders and other individuals.

Our generation, transmission, distribution and fuel storage facilities, information technology systems and other infrastructure or physical assets, as well as information processed in our systems (e.g., information regarding our customers, employees, operations, infrastructure and assets) could be affected by cyber security incidents, including those caused by human error.

Our industry has begun to see an increased volume and sophistication of cyber security incidents from international activist organizations, Nation States and individuals. Cyber security incidents could harm our businesses by limiting our generating, transmitting and distributing capabilities, delaying our development and construction of new facilities or capital improvement projects to existing facilities, disrupting our customer operations or causing the release of customer information, all of which could expose us to liability.

Our generation, transmission systems and natural gas pipelines are part of an interconnected system. Therefore, a disruption caused by the impact of a cyber security incident of the regional electric transmission grid, natural gas pipeline infrastructure or other fuel sources of our third party service providers' operations, could also negatively impact our business.

Our supply chain for procurement of digital equipment may expose software or hardware to these risks and could result in a breach or significant costs of remediation. In addition, such an event would likely receive federal and state regulatory scrutiny. We are unable to quantify the potential impact of cyber security threats or subsequent related actions. These potential cyber security incidents and regulatory action could result in a material decrease in revenues and may cause significant additional costs (e.g., penalties, third party claims, repairs, insurance or compliance) and potentially disrupt our supply and markets for natural gas, oil and other fuels.

We maintain security measures to protect our information technology and control systems, network infrastructure and other assets. However, these assets and the information they process may be vulnerable to cyber security incidents, including the resulting disability, or failures of assets or unauthorized access to assets or information. If our technology systems or those of our third-party service providers were to fail or be breached, we may be unable to fulfill critical business functions. We are unable to quantify the potential impact of cyber security incidents on our business, our brand, and our reputation. The cyber security threat is dynamic and evolves continually, and our efforts to prioritize network monitoring may not be effective given the constant changes to threat vulnerability.

Our operating results may fluctuate on a seasonal and quarterly basis and can be adversely affected by milder weather.

Our electric and natural gas utility businesses are seasonal and weather patterns can have a material impact on our operating performance. Demand for electricity is often greater in the summer and winter months associated with cooling and heating. Because natural gas is heavily used for residential and commercial heating, the demand depends heavily upon weather patterns. A significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. Unusually mild winters and summers could have an adverse effect on our financial condition, results of operations or cash flows.

Our operations use third party contractors in addition to employees to perform periodic and on-going work.

We rely on third party contractors to perform work for operations, maintenance and construction. We have contractual arrangements with these contractors which typically include performance standards, progress payments, insurance requirements and security for performance.

Cyber security breaches have at times exploited third party equipment or software in order to gain access. Poor vendor performance could impact on going operations, restoration operations, our reputation and could introduce financial risk or risks of fines.

Public Policy Risks

We may be subject to legislative and regulatory responses to climate change, with which compliance could be difficult and costly.

Legislative and regulatory responses related to climate change and new interpretations of existing laws create financial risk as our facilities may be subject to additional regulation at either the state or federal level in the future. Such regulations could impose substantial costs on our system.

We may be subject to climate change lawsuits. An adverse outcome could require substantial capital expenditures and could possibly require payment of substantial penalties or damages. Defense costs associated with such litigation can also be significant. Such payments or expenditures could affect results of operations, financial condition or cash flows if such costs are not recovered through regulated rates.

Although the United States has not adopted any international or federal GHG emission reduction targets, many states and localities may continue to pursue climate policies in the absence of federal mandates. All of the steps that Xcel Energy has taken to date to reduce GHG emissions, including energy efficiency measures, adding renewable generation or retiring or converting coal plants to natural gas, occurred under state-endorsed resource plans, renewable energy standards and other state policies. While those actions likely would have put Xcel Energy in a good position to meet federal or international standards being discussed, the lack of federal action does not adversely impact these state-endorsed actions and plans.

If our regulators do not allow us to recover all or a part of the cost of capital investment or the O&M costs incurred to comply with the mandates, it could have a material effect on our results of operations, financial condition or cash flows.

Increased risks of regulatory penalties could negatively impact our business.

The Energy Act increased civil penalty authority for violation of FERC statutes, rules and orders. The FERC can impose penalties of up to $1.3 million per violation per day, particularly as it relates to energy trading activities for both electricity and natural gas. In addition, NERC electric reliability standards and critical infrastructure protection requirements are mandatory and subject to potential financial penalties. Additionally, the PHMSA, Occupational Safety and Health Administration and other federal agencies have penalty authority. In the event of serious incidents, these agencies have become more active in pursuing penalties. Some states have the authority to impose substantial penalties. If a serious reliability or safety incident did occur, it could have a material effect on our results of operations, financial condition or cash flows.

Environmental Risks

We are subject to environmental laws and regulations, with which compliance could be difficult and costly.

We are subject to environmental laws and regulations that affect many aspects of our operations, including air emissions, water quality, wastewater discharges and the generation, transport and disposal of solid wastes and hazardous substances. Laws and regulations require us to obtain permits, licenses, and approvals and to comply with a variety of environmental requirements.

Environmental laws and regulations can also require us to restrict or limit the output of facilities or the use of certain fuels, shift generation to lower-emitting, install pollution control equipment, clean up spills and other contamination and correct environmental hazards. Environmental regulations may also lead to shutdown of existing facilities.

Failure to meet requirements of environmental mandates may result in fines or penalties. We may be required to pay all or a portion of the cost to remediate (i.e., clean-up) sites where our past activities, or the activities of other parties, caused environmental contamination.

We are subject to mandates to provide customers with clean energy, renewable energy and energy conservation offerings. It could have a material effect on our results of operations, financial condition or cash flows if our regulators do not allow us to recover the cost of capital investment or the O&M costs incurred to comply with the requirements.

In addition, existing environmental laws or regulations may be revised and new laws or regulations may be adopted. We may also incur additional unanticipated obligations or liabilities under existing environmental laws and regulations.

We are subject to physical and financial risks associated with climate change and other weather, natural disaster and resource depletion impacts.

Climate change can create physical and financial risk. Physical risks include changes in weather conditions and extreme weather events.

Our customers' energy needs vary with weather. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease. Increased energy use due to weather changes may require us to invest in generating assets, transmission and infrastructure. Decreased energy use due to weather changes may result in decreased revenues. Extreme weather conditions in general require system backup, costs, and can contribute to increased system stress, including service interruptions. Extreme weather conditions creating high energy demand may raise electricity prices, increasing the cost of energy we provide to our customers.

Severe weather impacts our service territories, primarily when thunderstorms, flooding, tornadoes, wildfires and snow or ice storms occur. To the extent the frequency of extreme weather events increases, this could increase our cost of providing service. Periods of extreme temperatures could impact our ability to meet demand. Changes in precipitation resulting in droughts or water shortages could adversely affect our operations. Drought conditions also contribute to the increase in wildfire risk from our electric generation facilities. While we carry liability insurance, given an extreme event, if Xcel Energy was found to be liable for wildfire damages, amounts that potentially exceed our coverage could negatively impact our results of operations, financial condition or cash flows. Drought or water depletion could adversely impact our ability to provide electricity to customers and increase the price paid for energy. We may not recover all costs related to mitigating these physical and financial risks.

Climate change may impact a region's economy, which could impact our sales and revenues. The price of energy has an impact on the economic health of our communities. The cost of additional regulatory requirements, such as regulation of GHG, could impact the availability of goods and prices charged by our suppliers which would normally be borne by consumers through higher prices for energy and purchased goods. To the extent financial markets view climate change and emissions of GHGs as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less than ideal terms and conditions.

Item 1B — Unresolved Staff Comments

None.

Item 2 — Properties

Virtually all of the utility plant property of NSP-Minnesota, NSP-Wisconsin, SPS and PSCo is subject to the lien of their first mortgage bond indentures.

Electric Generating Stations:

NSP-Minnesota

Station, Location and Unit	Fuel	Installed	MW [(a)]	
Steam:				
A.S. King-Bayport, MN, 1 Unit	Coal	1968	511	
Sherco-Becker, MN				
Unit 1	Coal	1976	680	
Unit 2	Coal	1977	682	
Unit 3	Coal	1987	517	(b)
Monticello, MN, 1 Unit	Nuclear	1971	617	
PI-Welch, MN				
Unit 1	Nuclear	1973	521	
Unit 2	Nuclear	1974	519	
Various locations, 4 Units	Wood/Refuse	Various	36	(c)
Combustion Turbine:				
Angus Anson-Sioux Falls, SD, 3 Units	Natural Gas	1994 - 2005	327	
Black Dog-Burnsville, MN, 3 Units	Natural Gas	1987 - 2002	494	(d)
Blue Lake-Shakopee, MN, 6 Units	Natural Gas	1974 - 2005	453	
High Bridge-St. Paul, MN, 3 Units	Natural Gas	2008	530	
Inver Hills-Inver Grove Heights, MN, 6 Units	Natural Gas	1972	282	
Riverside-Minneapolis, MN, 3 Units	Natural Gas	2009	454	
Various locations, 14 Units	Natural Gas	Various	67	
Wind:				
Border-Rolette County, ND, 75 Units	Wind	2015	148	(e)
Courtenay Wind, ND, 100 Units	Wind	2016	195	(e)
Grand Meadow-Mower County, MN, 67 Units	Wind	2008	101	(e)
Nobles-Nobles County, MN., 134 Units	Wind	2010	200	(e)
Pleasant Valley-Mower County, MN, 100 Units	Wind	2015	196	(e)
		Total	7,530	

(a) Summer 2018 net dependable capacity.
(b) Based on NSP-Minnesota's ownership of 59%.
(c) Refuse-derived fuel is made from municipal solid waste.
(d) Black Dog Unit 6 was commissioned and placed into operation in the third quarter of 2018.
(e) Values disclosed are the maximum generation levels for these wind units. Capacity is attainable only when wind conditions are sufficiently available (on-demand net dependable capacity is zero).

NSP-Wisconsin

Station, Location and Unit	Fuel	Installed	MW [(a)]	
Steam:				
Bay Front-Ashland, WI, 3 Units	Coal/Wood/Natural Gas	1948 - 1956	56	
French Island-La Crosse, WI, 2 Units	Wood/Refuse	1940 - 1948	16	(b)
Combustion Turbine:				
French Island-La Crosse, WI, 2 Units	Oil	1974	122	
Wheaton-Eau Claire, WI, 5 Units	Natural Gas/Oil	1973	234	
Hydro:				
Various locations, 63 Units	Hydro	Various	135	
		Total	563	

(a) Summer 2018 net dependable capacity.
(b) Refuse-derived fuel is made from municipal solid waste.

PSCo

Station, Location and Unit	Fuel	Installed	MW [(a)]	
Steam:				
Comanche-Pueblo, CO [(b)]				
Unit 1	Coal	1973	325	
Unit 2	Coal	1975	335	
Unit 3	Coal	2010	500	(c)
Craig-Craig, CO, 2 Units [(d)]	Coal	1979 - 1980	82	(e)
Hayden-Hayden, CO, 2 Units	Coal	1965 - 1976	233	(f)
Pawnee-Brush, CO, 1 Unit	Coal	1981	505	
Cherokee-Denver, CO, 1 Unit	Natural Gas	1968	310	
Combustion Turbine:				
Blue Spruce-Aurora, CO, 2 Units	Natural Gas	2003	264	
Cherokee-Denver, CO, 3 Units	Natural Gas	2015	576	
Fort St. Vrain-Platteville, CO, 6 Units	Natural Gas	1972 - 2009	968	
Rocky Mountain-Keenesburg, CO, 3 Units	Natural Gas	2004	580	
Various locations, 6 Units	Natural Gas	Various	171	
Hydro:				
Cabin Creek-Georgetown, CO				
Pumped Storage, 2 Units	Hydro	1967	210	
Various locations, 9 Units	Hydro	Various	26	
Wind:				
Rush Creek, CO, 300 units	Wind	2018	600	(g)
		Total	5,685	

(a) Summer 2018 net dependable capacity.
(b) In 2018, the CPUC approved early retirement of PSCo's Comanche Units 1 and 2 in 2022 and 2025, respectively.
(c) Based on PSCo's ownership of 67%.
(d) Craig Unit 1 is expected to be retired early in 2025.
(e) Based on PSCo's ownership of 10%.
(f) Based on PSCo's ownership of 75% of Unit 1 and 37% of Unit 2.
(g) Generation capability is based on the maximum output level of wind units, including the Rush Creek Wind Project. Capacity is attainable only when wind conditions are sufficiently available (on-demand net dependable capacity is zero).

SPS

Station, Location and Unit	Fuel	Installed	MW [(a)]
Steam:			
Cunningham-Hobbs, NM, 2 Units	Natural Gas	1957 - 1965	251
Harrington-Amarillo, TX, 3 Units	Coal	1976 - 1980	1,018
Jones-Lubbock, TX, 2 Units	Natural Gas	1971 - 1974	486
Maddox-Hobbs, NM, 1 Unit	Natural Gas	1967	112
Nichols-Amarillo, TX, 3 Units	Natural Gas	1960 - 1968	457
Plant X-Earth, TX, 4 Units	Natural Gas	1952 - 1964	411
Tolk-Muleshoe, TX, 2 Units	Coal	1982 - 1985	1,067
Combustion Turbine:			
Cunningham-Hobbs, NM, 2 Units	Natural Gas	1998	209
Jones-Lubbock, TX, 2 Units	Natural Gas	2011 - 2013	334
Maddox-Hobbs, TX, 1 Unit	Natural Gas	1963 - 1976	61
		Total	4,406

(a) Summer 2018 net dependable capacity.

Electric utility overhead and underground transmission and distribution lines (measured in conductor miles) at Dec. 31, 2018:

Conductor Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
500 KV	2,917	—	—	—
345 KV	13,560	3,415	4,062	9,028
230 KV	2,202	—	12,053	9,675
161 KV	615	1,823	—	—
138 KV	—	—	91	—
115 KV	7,372	1,817	5,051	14,493
Less than 115 KV . . .	86,185	32,831	78,446	25,820

Electric utility transmission and distribution substations at Dec. 31, 2018:

	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
Quantity	348	203	232	459

Natural gas utility mains at Dec. 31, 2018:

Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS	WGI
Transmission .	90	3	2,080	20	11
Distribution. . .	10,437	2,466	22,518	—	—

Item 3 — Legal Proceedings

Xcel Energy is involved in various litigation matters that are being defended and handled in the ordinary course of business. Assessment of whether a loss is probable or is a reasonable possibility, and whether a loss or a range of loss is estimable, often involves a series of complex judgments regarding future events. Management maintains accruals for losses that are probable of being incurred and subject to reasonable estimation. Management may be unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to, when (1) damages sought are indeterminate, (2) proceedings are in the early stages or (3) matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

See Note 12 to the consolidated financial statements, Item 1 and Item 7 for further information.

Item 4 — Mine Safety Disclosures

None.

PART II

Item 5 — Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Stock Data

Xcel Energy Inc.'s common stock was listed on the New York Stock Exchange (NYSE) in 2017, but moved to the Nasdaq Global Select Market (Nasdaq) in 2018. The trading symbol is XEL. The number of common stockholders of record as of Dec. 31, 2018 was approximately 57,059.

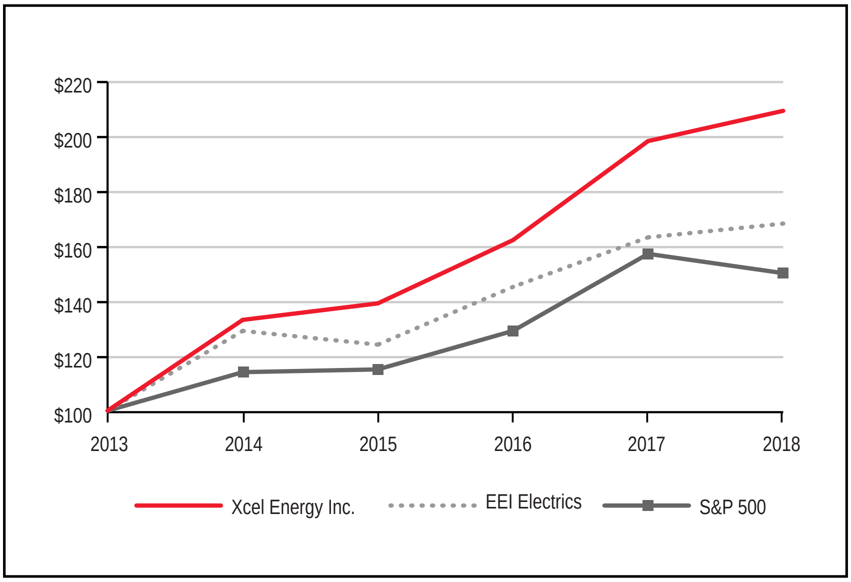
See Item 7 for further information.

The following compares our cumulative TSR on common stock with the cumulative TSR of the EEI Investor-Owned Electrics Index and the Standard & Poor's 500 Composite Stock Price Index over the last five years (assuming a $100 investment on Dec. 31, 2013, and the reinvestment of all dividends).

The EEI Investor-Owned Electrics Index (market capitalization-weighted) included 42 companies at year-end and is a broad measure of industry performance.

COMPARISON OF FIVE YEAR CUMULATIVE TOTAL RETURN*

Xcel Energy Inc., the EEI Investor-Owned Electrics and the Standard & Poor's 500



* $100 invested on Dec. 31, 2013 in stock or index — including reinvestment of dividends. Fiscal years ended Dec. 31.

Securities Authorized for Issuance Under Equity Compensation Plans

Information required under Item 5 — Securities Authorized for Issuance Under Equity Compensation Plans is contained in Xcel Energy Inc.'s Proxy Statement for its 2018 Annual Meeting of Shareholders, which is incorporated by reference.

Purchases of Equity Securities by Issuer and Affiliated Purchasers

For the quarter ended Dec. 31, 2018, no equity securities that are registered by Xcel Energy Inc. pursuant to Section 12 of the Securities Exchange Act of 1934 were purchased by or on behalf of us or any of our affiliated purchasers.

Item 6 — Selected Financial Data

Selected financial data for Xcel Energy related to the five most recent years ended Dec. 31.

(Millions of Dollars, Millions of Shares, Except Per Share Data)	2018	2017	2016	2015	2014
Operating revenues	$ 11,537	$ 11,404	$ 11,107	$ 11,024	$ 11,686
Operating expenses [(a)]	9,572	9,181	8,867	9,024	9,738
Net income	1,261	1,148	1,123	984	1,021
Earnings available to common shareholders	1,261	1,148	1,123	984	1,021
Diluted earnings per common share	2.47	2.25	2.21	1.94	2.03
Financial information					
Dividends declared per common share	1.52	1.44	1.36	1.28	1.20
Total assets [(b)] [(c)]	45,987	43,030	41,155	38,821	36,958
Long-term debt [(c)] [(d)]	15,803	14,520	14,195	12,399	11,500

(a) As a result of adopting ASU No. 2017-07 (*Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, Topic 715),* $33 million and $26 million of pension costs were retrospectively reclassified from operating and maintenance expenses to other income, net on the consolidated statements of income for the years ended Dec. 31, 2017 and Dec. 31, 2016, respectively.

(b) As a result of adopting ASU No. 2015-17 (*Balance Sheet Classification of Deferred Taxes, Topic 740*), $140 million of current deferred income taxes was retrospectively reclassified to long-term deferred income tax liabilities on the consolidated balance sheet as of Dec. 31, 2015.

(c) As a result of adopting ASU No. 2015-03 (*Simplifying the Presentation of Debt Issuance Costs, Subtopic 835-30*), $92 million of deferred debt issuance costs was retrospectively reclassified from other non-current assets to long-term debt on the consolidated balance sheet as of Dec. 31, 2015.

(d) Includes capital lease obligations.

Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operations

Business Segments and Organizational Overview

Xcel Energy Inc. is a public utility holding company. Xcel Energy's operations include the activity of four utility subsidiaries that serve electric and natural gas customers in eight states. The utility subsidiaries serve customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Along with the utility subsidiaries, the TransCo subsidiaries, WYCO (a joint venture formed with CIG to develop and lease natural gas pipelines, storage and compression facilities) and WGI (an interstate natural gas pipeline company) comprise the regulated utility operations.

Xcel Energy Inc.'s immaterial nonregulated subsidiaries are Eloigne and Capital Services.

Management's Strategic Priorities

Xcel Energy's vision is to be the preferred and trusted provider of the energy our customers need. We strive to provide our investors an attractive value proposition and our customers with safe, clean and reliable energy services at a competitive price. This mission is enabled via three key strategic priorities:

- Lead the clean energy transition;
- Enhance the customer experience; and,
- Keep bills low.

Successful execution of our strategic objectives should allow Xcel Energy to continue to deliver a competitive total return for our shareholders.

Lead the clean energy transition

For more than a decade, we have managed the risk of climate change and increasing customer demand for renewable energy through a clean energy strategy that consistently reduces carbon emissions and transitions our operations for the future. As a result, we have successfully reduced our carbon emissions to our customers by approximately 40% from 2005 to 2018. We expect to reduce our carbon footprint by 80% by 2030 (over 2005 levels). We have also announced our vision to serve all customers with 100% zero-carbon emissions by 2050.

Our service territories benefit from the geographic concentration of favorable renewable resources. Strong wind and high solar irradiance yield high generation capacity factors, which lowers the cost of these resources. The combination of high capacity factors, grid options from transmission investment and market operations, improved supply chain, technological improvements and the extension of the renewable tax credits translates into low renewable energy costs for our customers. As a result, we are able to invest in renewable generation, in which the capital costs are largely or completely offset by fuel savings. This provides us the opportunity to lower the emission profile of our generation fleet, grow our renewable portfolio and provide significant fuel savings to our customers. We call this our "Steel for Fuel" strategy.

We are transitioning how we produce, deliver and encourage the efficient use of energy through four primary mechanisms:

- Increasing the use of affordable renewable energy;
- Offering energy efficiency programs for customers;
- Retiring or repowering coals units and modernizing our generating plants; and,
- Advancing power grid capabilities.

We have announced ambitious plans to add approximately 3,600 MW of wind energy on our system by 2021.

In addition, the proposed CEP in Colorado encompasses the retirement of 660 MW from two coal-fired units at Comanche and the addition of up to 1,100 MW of wind, 700 MW of solar and 275 MW of battery storage.

Enhance the customer experience

The utility landscape is changing, and we must continue to thoughtfully anticipate and address the future needs of our stakeholders, including our customers, policymakers, employees and shareholders. Our customers expect to have choices, and we are committed to providing options and solutions that they want and value at a competitive price.

We will continue to expand our production of renewable energy, including wind and solar alternatives, and further develop and promote DSM, conservation and renewable programs. We are also in the process of transforming our transmission and distribution systems to accommodate increased levels of renewables, distributed energy resources and corresponding data growth, while maintaining high levels of reliability and security and keeping customer bills affordable. We also are expanding our Renewable*Connect program, which allows customers to choose how much of their energy comes from renewable sources. Renewable*Connect has regulatory approval in Minnesota, Colorado and Wisconsin. This is yet another way for us to add renewable energy and meet the needs of our customers. Importantly, Renewable*Connect does not negatively impact the bills of non-participants. Finally, we are improving our communications to enable customers to interact with us in the way they prefer.

Keep bills low

Xcel Energy is very focused on our customers and the impact our actions have on their bill. Our objective is to keep total bill increases at or below the rate of inflation so our prices remain competitive relative to alternatives. We expect to continue to keep our customer bills low by executing on our Steel for Fuel plan, controlling O&M costs and promoting energy efficiency and conservation.

Xcel Energy is working to keep long-term O&M expense relatively consistent without compromising reliability or safety. We intend to accomplish this objective by continually improving our processes, leveraging technology, proactively managing risk and maintaining a workforce that is prepared to meet the needs of our business today and tomorrow. In 2018, we experienced warmer than normal summer weather, which caused us to spend additional O&M for vegetation management and system maintenance due to the hot summer, business systems costs, investments to improve and enhance business processes and customer service, as well as damage prevention and remediation costs. However, we remain committed to our long-term objective of improving operating efficiencies and taking costs out of the business for the benefit of our customers and anticipate that our long-term O&M expense trend will remain relatively consistent.

Provide a competitive total return to investors and maintain strong investment grade credit rating

Through our disciplined approach to business growth, financial investment, operations and safety, we plan to:

- Deliver long-term annual EPS growth of 5% to 7%;
- Deliver annual dividend increases of 5% to 7%;
- Target a dividend payout ratio of 60% to 70% of annual ongoing EPS; and,
- Maintain senior secured debt credit ratings in the A range and senior unsecured debt credit ratings in the BBB+ to A range.

We have consistently achieved our financial objectives, meeting or exceeding our earnings guidance range for fourteen consecutive years, and we believe we are positioned to continue to deliver on our value proposition. Our ongoing earnings have grown approximately 6.1% and our dividend has grown approximately 4.5% annually from 2005 - 2018. In addition, our current senior unsecured debt credit ratings for Xcel Energy and its utility subsidiaries are in the BBB+ to A range, while our secured operating company debt ratings are in the A range.

Non-GAAP Financial Measures

The following discussion includes financial information prepared in accordance with GAAP, as well as certain non-GAAP financial measures such as the ongoing return on equity (ROE), electric margin, natural gas margin, ongoing earnings and ongoing diluted EPS. Generally, a non-GAAP financial measure is a measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are adjusted from measures calculated and presented in accordance with GAAP. Xcel Energy's management uses non-GAAP measures for financial planning and analysis, for reporting of results to the Board of Directors, in determining performance-based compensation, and communicating its earnings outlook to analysts and investors. Non-GAAP financial measures are intended to supplement investors' understanding of our performance and should not be considered alternatives for financial measures presented in accordance with GAAP. These measures are discussed in more detail below and may not be comparable to other companies' similarly titled non-GAAP financial measures.

Ongoing ROE

Ongoing ROE is calculated by dividing the net income or loss of Xcel Energy or each subsidiary, adjusted for certain nonrecurring items, by each entity's average stockholder's equity. We use these non-GAAP financial measures to evaluate and provide details of earnings results.

Electric and Natural Gas Margins

Electric margin is presented as electric revenues less electric fuel and purchased power expenses. Natural gas margin is presented as natural gas revenues less the cost of natural gas sold and transported. Expenses incurred for electric fuel and purchased power and the cost of natural gas are generally recovered through various regulatory recovery mechanisms. As a result, changes in these expenses are generally offset in operating revenues.

Management believes electric and natural gas margins provide the most meaningful basis for evaluating our operations because they exclude the revenue impact of fluctuations in these expenses. These margins can be reconciled to operating income, a GAAP measure, by including other operating revenues, cost of sales-other, O&M expenses, conservation and DSM expenses, depreciation and amortization and taxes (other than income taxes).

Earnings Adjusted for Certain Items (Ongoing Earnings and Ongoing Diluted EPS)

GAAP diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock (i.e., common stock equivalents) were settled. The weighted average number of potentially dilutive shares outstanding used to calculate Xcel Energy Inc.'s diluted EPS is calculated using the treasury stock method. Ongoing earnings reflect adjustments to GAAP earnings (net income) for certain items. Ongoing diluted EPS is calculated by dividing the net income or loss of each subsidiary, adjusted for certain items, by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period. Ongoing diluted EPS for each subsidiary is calculated by dividing the net income or loss of such subsidiary, adjusted for certain items, by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period.

We use these non-GAAP financial measures to evaluate and provide details of Xcel Energy's core earnings and underlying performance. We believe these measurements are useful to investors to evaluate the actual and projected financial performance and contribution of our subsidiaries. For the year ended Dec. 31, 2017, Xcel Energy recognized an estimated one-time, non-cash, income tax expense of approximately $23 million for net excess deferred tax assets which may not be recovered from customers or not attributable to regulated operations, increased valuation allowances, etc. due to the enactment of the TCJA in December 2017. For the year ended Dec. 31, 2018, there were no such adjustments to GAAP earnings and therefore GAAP earnings equal ongoing earnings.

See Note 7 to the consolidated financial statements for further information.

Results of Operations

Diluted EPS for Xcel Energy at Dec. 31:

	2018	2017			2016
Diluted Earnings (Loss) Per Share	GAAP and Ongoing Diluted EPS	GAAP Diluted EPS	Impact of TCJA [(a)]	Ongoing Diluted EPS	GAAP and Ongoing Diluted EPS
PSCo	$ 1.08	$ 0.97	$ (0.03)	$ 0.94	$ 0.91
NSP-Minnesota	0.96	0.96	0.05	1.01	0.96
SPS	0.42	0.31	(0.01)	0.30	0.30
NSP-Wisconsin	0.19	0.16	—	0.16	0.14
Equity earnings of unconsolidated subsidiaries [(a)]	0.04	0.07	(0.04)	0.03	0.05
Regulated utility [(b)]	2.69	2.47	(0.03)	2.45	2.35
Xcel Energy Inc. and other	(0.22)	(0.22)	0.07	(0.15)	(0.15)
Total [(b)]	$ 2.47	$ 2.25	$ 0.05	$ 2.30	$ 2.21

(a) Includes income taxes.

(b) Amounts may not add due to rounding.

Xcel Energy's management believes that ongoing earnings reflects management's performance in operating the company and provides a meaningful representation of the performance of Xcel Energy's core business. In addition, Xcel Energy's management uses ongoing earnings internally for financial planning and analysis, reporting results to the Board of Directors and when communicating its earnings outlook to analysts and investors.

Earnings Adjusted for Certain Items

2018 Comparison with 2017

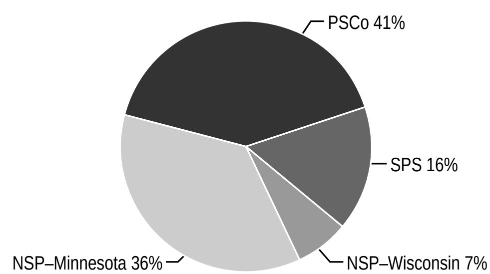
2017 Adjustment to GAAP Earnings — Impact of the TCJA — Xcel Energy recognized an estimated one-time, non-cash, income tax expense of approximately $23 million in the fourth quarter of 2017 for net excess deferred tax assets which may not be recovered from customers or not attributable to regulated operations, increased valuation allowances, etc. due to the enactment of the TCJA in December 2017. The income tax expense associated with the TCJA enactment has been excluded from Xcel Energy's 2017 ongoing earnings, given the non-recurring nature of the TCJA's broad and sweeping reform of the IRC.

See Note 7 to the consolidated financial statements for further information.

Differences between GAAP and ongoing earnings are due to the non-recurring impact of the TCJA experienced in 2017. Explanations for operating company results below exclude the offsetting impacts of the TCJA on sales, depreciation and amortization expense and income tax.

Xcel Energy — GAAP and ongoing earnings increased $0.22 and $0.17 per share, respectively. Earnings increased as a result of higher electric and natural gas revenues primarily due to favorable weather and sales growth and higher AFUDC. These positive factors were partially offset by increased O&M, depreciation and interest expenses. GAAP earnings for 2017 include the non-recurring negative impact of the TCJA.

2018 Ongoing Diluted EPS



PSCo — GAAP and ongoing 2018 earnings increased $0.11 and $0.14 per share, respectively. Increases were driven by higher natural gas margins largely due to a natural gas rate increase, higher electric margins reflecting favorable weather and sales growth, and additional AFUDC associated with the Rush Creek wind project. These items were partially offset by higher O&M expenses, interest charges, depreciation expense and property taxes.

NSP-Minnesota — 2018 GAAP earnings were consistent with 2017, while 2018 ongoing earnings decreased $0.05 per share. The decrease in ongoing earnings reflects higher depreciation expense and O&M expenses. These amounts were partially offset by higher electric and natural gas margins attributable to favorable weather.

SPS — 2018 GAAP and ongoing earnings increased $0.11 and $0.12 per share, respectively. Increases were primarily due to higher electric margins reflecting favorable weather and sales growth and a rate increase in New Mexico, AFUDC related to the Hale County wind project and lower interest charges. Increases were partially offset by higher depreciation expense.

NSP-Wisconsin — 2018 GAAP and ongoing earnings increased $0.03 per share. Increases reflect higher electric and natural gas rates and the impact of favorable weather and sales growth, which were partially offset by higher depreciation.

Xcel Energy Inc. and other — Xcel Energy Inc. and other primarily includes financing costs at the holding company. 2018 GAAP earnings were consistent with 2017, while 2018 ongoing earnings decreased $0.07 per share. Decrease was primarily due to higher interest expense related to additional debt and the change in the federal income tax rate.

2017 Comparison with 2016

Xcel Energy — GAAP earnings increased $0.04 per share for 2017. Ongoing earnings increased $0.09 per share, excluding the impact of the TCJA. Earnings were higher as a result of increased electric and natural gas margins to recover infrastructure investments, reduced O&M expenses, a lower ETR and higher AFUDC. These positive factors were partially offset by increased depreciation expense, interest charges and property taxes.

PSCo — GAAP earnings increased $0.06 per share for 2017. Ongoing earnings increased $0.03 per share, excluding the impact of the TCJA. The increase in earnings was driven by higher electric and natural gas margins, increased AFUDC primarily related to the Rush Creek wind project, a decrease in O&M expenses (timing of generation outages) and a lower ETR, partially offset by higher depreciation expense, interest charges and the impact of unfavorable weather.

NSP-Minnesota — GAAP earnings were flat for 2017. Ongoing earnings increased $0.05 per share, excluding the impact of the TCJA. The change reflects higher electric margins driven by a 2017 Minnesota rate increase as well as increased gas margins, a lower ETR and reduced O&M expenses. These positive factors were partially offset by higher depreciation expense due to increased invested capital as well as prior year amortization of Minnesota's excess depreciation reserve and higher property taxes.

SPS — GAAP earnings increased $0.01 per share for 2017. Ongoing earnings were flat, excluding the impact of the TCJA. Rate increases in Texas and New Mexico and a lower ETR were offset by higher depreciation expense (representing continued investment), O&M expenses (including the prior year deferrals associated with the Texas 2016 rate case), property taxes and the impact of unfavorable weather.

NSP-Wisconsin — GAAP and ongoing earnings increased $0.02 per share for 2017. The change in ongoing earnings was driven by a rise in electric and natural gas rates, partially offset by additional depreciation expense related to continued transmission and distribution investments and higher O&M expenses.

Equity earnings of unconsolidated subsidiaries — GAAP earnings increased $0.02 per share for 2017. Ongoing earnings of unconsolidated subsidiaries decreased $0.02 per share, excluding the impact of the TCJA. The decline primarily related to lower revenues due to lower rates at WYCO.

Changes in Diluted EPS

Components significantly contributing to changes in 2018 EPS compared with the same period in 2017 and 2017 EPS compared to 2016:

2018 vs. 2017

Diluted Earnings (Loss) Per Share	Dec. 31
GAAP diluted EPS — 2017	$ 2.25
Impact of the TCJA [(a)]	0.05
Ongoing diluted EPS — 2017	$ 2.30
Components of change — 2018 vs. 2017	
Higher electric margins (excluding TCJA impacts) [(a)]	0.31
Higher natural gas margins (excluding TCJA impacts) [(a)]	0.13
Higher AFUDC — equity	0.07
Higher O&M expenses	(0.10)
Higher depreciation and amortization (excluding TCJA impacts) [(a)]	(0.10)
Higher ETR (excluding TCJA impacts) [(a)]	(0.07)
Higher interest charges	(0.04)
Higher conservation and demand side management (DSM) program expenses (offset by higher revenues)	(0.02)
Higher taxes (other than income taxes)	(0.01)
GAAP and ongoing diluted EPS — 2018	$ 2.47
Estimated net impact of the TCJA, including assumptions regarding future regulatory proceedings: [(a)]	
Income tax — rate change and ARAM (net of deferral)	0.68
Electric margin reductions (net)	(0.46)
Natural gas margin reductions (net)	(0.06)
Depreciation and amortization reductions (Colorado prepaid pension)	(0.11)
Holding company — interest expense	(0.04)
Total	$ 0.01

2017 vs. 2016

Diluted Earnings (Loss) Per Share	Dec. 31
GAAP and ongoing diluted EPS — 2016	$ 2.21
Components of change — 2017 vs. 2016	
Higher electric margins [(a)]	0.16
Lower ETR [(b)]	0.07
Higher natural gas margins	0.03
Higher AFUDC — equity	0.03
Lower O&M expenses	0.03
Higher depreciation and amortization	(0.21)
Higher conservation and DSM program expenses [(c)]	(0.03)
Higher interest charges	(0.02)
Higher taxes (other than income taxes)	(0.02)
Equity earnings of unconsolidated subsidiaries	(0.02)
Other, net	0.02
GAAP diluted EPS — 2017	$ 2.25
Impact of the TCJA	0.05
Ongoing diluted EPS — 2017	$ 2.30

(a) Includes an increase of $23 million in revenues from conservation and DSM programs, offset by related expenses, for the twelve months ended Dec. 31, 2017.

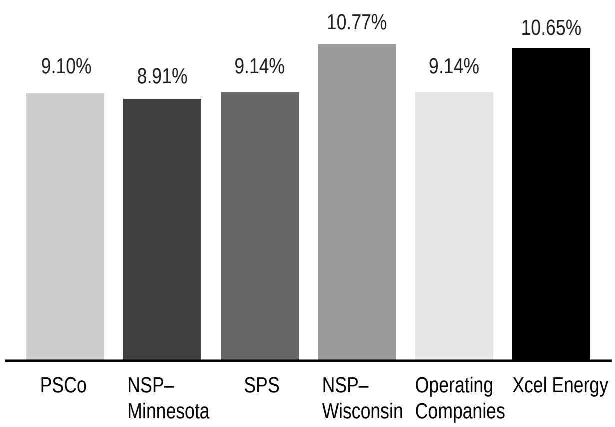
(b) ETR includes the impact of an additional $20 million of wind PTCs for the twelve months ended Dec. 31, 2017, which are largely flowed back to customers through electric margin, as well as the impact of the TCJA recorded in the fourth quarter of 2017.

(c) Offset by higher revenues.

ROE for Xcel Energy and its utility subsidiaries at Dec. 31:

	2018	2017		
ROE	GAAP and Ongoing ROE	GAAP ROE	Impact of the TCJA	Ongoing ROE
PSCo	9.10%	8.90%	(0.24)%	8.66%
NSP-Minnesota	8.91	9.05	0.45	9.50
SPS	9.14	7.84	(0.30)	7.54
NSP-Wisconsin	10.77	9.41	0.09	9.50
Operating Companies	9.14	8.84	0.03	8.87
Xcel Energy	10.65	10.21	0.21	10.42

2018 Ongoing Return on Equity



Reconciliation of GAAP earnings (net income) to ongoing earnings and GAAP diluted EPS to ongoing diluted EPS for the years ended Dec. 31:

(Millions of Dollars)	2018	2017	2016
GAAP earnings	$ 1,261	$ 1,148	$ 1,123
Estimated impact of TCJA	—	23	—
Ongoing earnings	$ 1,261	$ 1,171	$ 1,123

Diluted EPS	2018	2017	2016
GAAP diluted EPS	$ 2.47	$ 2.25	$ 2.21
Estimated impact of TCJA	—	0.05	—
Ongoing diluted EPS	$ 2.47	$ 2.30	$ 2.21

Statement of Income Analysis

The following summarizes the items that affected the individual revenue and expense items reported in the consolidated statements of income.

Estimated Impact of Temperature Changes on Earnings — Unusually hot summers or cold winters increase electric and natural gas sales, while mild weather reduces electric and natural gas sales. The estimated impact of weather on earnings is based on the number of customers, temperature variances and the amount of natural gas or electricity historically used per degree of temperature. Weather deviations from normal levels can affect Xcel Energy's financial performance.

Degree-day or THI data is used to estimate amounts of energy required to maintain comfortable indoor temperature levels based on each day's average temperature and humidity. HDD is the measure of the variation in the weather based on the extent to which the average daily temperature falls below 65° Fahrenheit. CDD is the measure of the variation in the weather based on the extent to which the average daily temperature rises above 65° Fahrenheit. Each degree of temperature above 65° Fahrenheit is counted as one CDD, and each degree of temperature below 65° Fahrenheit is counted as one HDD. In Xcel Energy's more humid service territories, a THI is used in place of CDD, which adds a humidity factor to CDD. HDD, CDD and THI are most likely to impact the usage of Xcel Energy's residential and commercial customers. Industrial customers are less sensitive to weather.

Normal weather conditions are defined as either the 20-year or 30-year average of actual historical weather conditions. The historical period of time used in the calculation of normal weather differs by jurisdiction, based on regulatory practice. To calculate the impact of weather on demand, a demand factor is applied to the weather impact on sales. Extreme weather variations, windchill and cloud cover may not be reflected in weather-normalized estimates. Percentage increase (decrease) in normal and actual HDD, CDD and THI:

	2018 vs. Normal	2017 vs. Normal	2018 vs. 2017	2016 vs. Normal	2017 vs. 2016
HDD	2.2%	(10.0)%	12.2%	(13.4)%	2.6%
CDD	26.7	6.5	20.5	11.1	(3.5)
THI	37.3	(11.3)	56.9	7.7	(18.5)

Weather — Estimated impact of temperature variations on EPS compared with normal weather conditions:

	2018 vs. Normal	2017 vs. Normal	2018 vs. 2017	2016 vs. Normal	2017 vs. 2016
Retail electric	$ 0.114	$ (0.036)	$ 0.150	$ 0.004	$ (0.040)
Firm natural gas	0.007	(0.023)	0.030	(0.025)	0.002
Total (excluding decoupling)	$ 0.121	$ (0.059)	$ 0.180	$ (0.021)	$ (0.038)
Decoupling — Minnesota electric	(0.051)	0.022	(0.073)	(0.002)	0.024
Total (adjusted for recovery from decoupling)	$ 0.070	$ (0.037)	$ 0.107	$ (0.023)	$ (0.014)

Sales Growth (Decline) — Sales growth (decline) for actual and weather-normalized sales in 2018 compared to the same period in 2017:

	2018 vs. 2017				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential	3.6%	5.8%	8.6%	5.7%	5.4%
Electric C&I	1.5	1.1	5.4	3.2	2.4
Total retail electric sales	2.2	2.5	5.9	3.9	3.2
Firm natural gas sales	9.3	14.6	N/A	13.1	11.3

	2018 vs. 2017				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential	1.8%	(0.5)%	2.0%	0.2%	0.8%
Electric C&I	1.2	(0.4)	4.6	2.3	1.5
Total retail electric sales . .	1.3	(0.4)	4.1	1.7	1.3
Firm natural gas sales	2.2	2.7	N/A	3.1	2.4

Weather-normalized 2018 Electric Sales Growth (Decline)

- PSCo — Higher residential sales growth reflects customer additions and slightly higher use per customer. C&I growth was due to an increase in customers and higher use per customer, predominately from the fabricated metal, food products, metal mining and oil and gas extraction industries.
- NSP-Minnesota — Residential sales decrease was a result of lower use per customer, partially offset by customer growth. The decline in C&I sales was due to an increase in customers offset by lower use per customer. Increased sales to large customers in manufacturing and energy were offset by declines in services.
- SPS — Residential sales grew largely due to higher use per customer and customer additions. The increase in C&I sales was driven by the oil and natural gas industry in the Permian Basin.
- NSP-Wisconsin — Sales growth was primarily attributable to customer additions, partially offset by lower use per customer. C&I growth was largely due to higher use per large customer, customer additions and increased sales to sand mining and energy industries.

Weather-normalized 2018 Natural Gas Sales Growth

- Higher natural gas sales reflect an increase in the number of customers combined with increasing customer use.

	2017 vs. 2016				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential	(1.8)%	(2.1)%	(3.5)%	(0.8)%	(2.1)%
Electric C&I	(0.1)	(1.4)	1.3	2.2	(0.1)
Total retail electric sales . .	(0.6)	(1.6)	0.2	1.3	(0.7)
Firm natural gas sales	(2.2)	9.3	N/A	11.3	2.1

	2017 vs. 2016				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential	(1.6)%	(0.7)%	(1.2)%	0.3 %	(1.0)%
Electric C&I	0.1	(1.0)	1.5	2.5	0.2
Total retail electric sales . .	(0.4)	(1.0)	0.9	1.8	(0.2)
Firm natural gas sales	0.6	4.7	N/A	5.7	2.2

	2017 vs. 2016 (Excluding Leap Day) [b]				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized - adjusted for leap day					
Electric residential [a]	(1.3)%	(0.5)%	(1.0)%	0.6%	(0.8)%
Electric C&I	0.3	(0.8)	1.8	2.7	0.4
Total retail electric sales . .	(0.2)	(0.7)	1.1	2.1	0.1
Firm natural gas sales	1.1	5.2	N/A	6.3	2.7

(a) Extreme weather variations, windchill and cloud cover may not be reflected in weather-normalized and actual growth (decline) estimates.

(b) Estimated impact of the 2016 leap day is excluded to present a more comparable year-over-year presentation. Estimated impact of the additional day of sales in 2016 was approximately 0.3% for retail electric and 0.5% for firm natural gas for the twelve months ended.

Weather-normalized 2017 Electric Sales Growth (Decline) (Excluding Leap Day)

- PSCo's decline in residential sales reflects lower use per customer, partially offset by customer additions. C&I growth was mainly due to an increase in customers and higher use for large C&I customers that support the mining, oil and natural gas industries, partially offset by lower use for the small C&I class.
- NSP-Minnesota's residential sales decrease was a result of lower use per customer, partially offset by customer growth. The decline in C&I sales was largely due to reduced usage, which offset an increase in the number of customers. Declines in services more than offset increased sales to large customers in manufacturing and energy industries.
- SPS' residential sales fell largely due to lower use per customer. The increase in C&I sales reflects customer additions and greater use for large C&I customers driven by the oil and natural gas industry in the Permian Basin.
- NSP-Wisconsin's residential sales increase was primarily attributable to higher use per customer and customer additions. C&I growth was largely due to higher use per customer and increased sales to customers in the sand mining industry and large customers in the energy and manufacturing industries.

Weather-normalized 2017 Natural Gas Sales Growth

- Higher natural gas sales reflect an increase in the number of customers, partially offset by a decline in customer use.

Weather-normalized sales for 2019 are projected to be relatively consistent with 2018 levels for retail electric customers and within a range of 0.0% to 1.0% over 2018 levels for retail natural gas customers.

Electric Margin

Electric revenues and fuel and purchased power expenses are impacted by fluctuations in the price of natural gas, coal and uranium used in the generation of electricity. However, these price fluctuations have minimal impact on electric margin due to fuel recovery mechanisms that recover fuel expenses. Electric margin was reduced by approximately $105 million in 2018 and $130 million in 2017 for PTCs (grossed up for federal income tax) which were returned to customers. Margin reductions for PTCs are largely offset by income tax benefits.

Electric revenues and margin before and after the impact of the TCJA:

(Millions of Dollars)	2018	2017	2016
Electric revenues before TCJA impact	$ 10,046	$ 9,676	$ 9,500
Electric fuel and purchased power before TCJA impact	(3,867)	(3,757)	(3,718)
Electric margin before TCJA impact	$ 6,179	$ 5,919	$ 5,782
TCJA impact (offset as a reduction in income tax)	(314)	—	—
Electric margin	$ 5,865	$ 5,919	$ 5,782

Electric Margin

(Millions of Dollars)	2018 vs. 2017
Estimated impact of weather (net of Minnesota decoupling)	$ 63
Retail sales growth (net of Minnesota decoupling and sales true-up)	52
Non-fuel riders	45
Purchased capacity costs	38
Wholesale transmission revenue (net)	31
Retail rate increase (Wisconsin, New Mexico and Michigan)	20
Other (net)	11
Total increase in electric margin before TCJA impact	$ 260
TCJA impact (offset as a reduction in income tax)	(314)
Total decrease in electric margin	$ (54)

(Millions of Dollars)	2017 vs. 2016
Retail rate increases (Texas, Minnesota, New Mexico and Wisconsin)	$ 123
Non-fuel riders	33
Conservation and DSM revenues (offset by expenses)	23
Decoupling (weather portion — Minnesota)	18
Purchased capacity costs	8
Wholesale transmission revenue (net of costs)	(38)
Estimated impact of weather	(30)
Conservation incentive	(18)
Other (net)	18
Total increase in electric margin	$ 137

Natural Gas Margin

Total natural gas expense varies with changing sales requirements and the cost of natural gas. However, fluctuations in the cost of natural gas has minimal impact on natural gas margin due to natural gas cost recovery mechanisms.

Natural gas revenues and margin before and after the impact of the TCJA:

(Millions of Dollars)	2018	2017	2016
Natural gas revenues before TCJA impact	$ 1,778	$ 1,650	$ 1,531
Cost of natural gas sold and transported	(843)	(823)	(733)
Natural gas margin before TCJA impact	$ 935	$ 827	$ 798
TCJA impact (offset as a reduction in income tax)	(39)	—	—
Natural gas margin	$ 896	$ 827	$ 798

Natural Gas Margin

(Millions of Dollars)	2018 vs. 2017
Retail rate increase (Colorado, Wisconsin and Michigan)	$ 58
Estimated impact of weather	24
Infrastructure and integrity riders	13
Sales growth	6
Conservation revenue (offset by expenses)	3
Other (net)	4
Total increase in natural gas margin before TCJA impact	$ 108
TCJA impact (offset as a reduction in income tax)	(39)
Total increase in natural gas margin	$ 69

(Millions of Dollars)	2017 vs. 2016
Infrastructure and integrity riders	$ 18
Retail sales growth, excluding weather impact	7
Estimated impact of weather	1
Other (net)	3
Total increase in natural gas margin	$ 29

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses increased $82 million, or 3.6%, for 2018. Significant changes are summarized below:

(Millions of Dollars)	2018 vs. 2017
Business systems and contract labor	$ 39
Distribution costs	19
Natural gas systems damage prevention and other remediation	12
Generation plant costs (including increased wind O&M)	11
Nuclear plant operations and amortization	(9)
Other (net)	10
Total increase in O&M expenses	$ 82

- Business systems and contract labor costs increased due to growing network and storage needs, cybersecurity, initiatives to support our customer strategy, and initiatives to improve business processes;
- Distribution costs reflect higher maintenance expenses, including vegetation management; and,
- Nuclear plant operations and amortization are lower largely reflecting savings initiatives and reduced refueling outage costs.

O&M expenses decreased $23 million, or 1.0%, for 2017. Significant changes are summarized as follows:

(Millions of Dollars)	2017 vs. 2016
Nuclear plant operations and amortization	$ (27)
Plant generation costs	(23)
Transmission costs	(2)
Employee benefits expense	17
Texas 2016 electric rate case cost deferral	16
Electric distribution costs	2
Other (net)	(6)
Total decrease in O&M expenses	$ (23)

- Nuclear plant operations and amortization expenses are lower mostly due to reduced refueling outage costs and operating efficiencies.
- Plant generation costs decreased as a result of lower expenses associated with planned outages and overhauls at a number of generation facilities.
- Employee benefits expense includes the recognition of an $8 million pension settlement expense in the fourth quarter of 2017.

Conservation and DSM Program Expenses — Conservation and DSM program expenses increased $17 million, or 6.2%, for 2018. The increase was primarily due to recovery for conservation programs to assist customers in reducing energy use. Conservation and DSM expenses are generally recovered concurrently through riders and base rates. Timing of recovery may vary from when costs are incurred.

Conservation and DSM program expenses increased $28 million, or 11.4%, for 2017 compared with 2016. The increase was due to higher customer participation in electric conservation programs and recovery rates, mostly in Minnesota.

Depreciation and Amortization — Depreciation and amortization increased $163 million, or 11%, for 2018. The increase was primarily driven by capital investments and additional amortization of a prepaid pension asset in Colorado (approximately $75 million) related to TCJA settlements, which were offset by lower income taxes.

Depreciation and amortization increased $176 million, or 13.5%, for 2017 compared with 2016. The increase was primarily due to capital investments and prior year amortization of the excess depreciation reserve in Minnesota.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased $11 million, or 2.0%, for 2018. The increase was primarily due to higher property taxes.

Taxes (other than income taxes) increased $13 million, or 2.4%, for 2017 compared with 2016. The increase was primarily due to higher property taxes in Minnesota and Texas.

AFUDC, Equity and Debt — AFUDC increased $46 million for 2018. The increase was primarily due to the Rush Creek and Hale wind projects and other capital investments.

AFUDC increased $23 million for 2017 compared with 2016. The increase was primarily due to higher CWIP, particularly the Rush Creek wind project.

Interest Charges — Interest expense increased $37 million, or 5.6%, for 2018. The increase was related to higher debt levels to fund capital investments, partially offset by refinancings at lower interest rates.

Interest charges increased $16 million, or 2.5%, for 2017 compared with 2016. The increase was related to higher debt levels to fund capital investments, partially offset by refinancings at lower interest rates.

Income Taxes — Income tax expense decreased $361 million for 2018. The decrease was primarily driven by a lower federal tax rate due to the TCJA, lower pretax earnings, a one time, non-cash income tax expense related to the TCJA in 2017, an increase in plant-related regulatory differences related to ARAM (net of deferrals), 2018 non-plant excess accumulated deferred income tax amortization, and the impact of 2018 investment tax credits. These were partially offset by a higher tax benefit for the resolution of past appeals/audits in 2017 and a higher tax benefit for adjustments in 2017. The ETR was 12.6% for 2018 compared with 32.1% for 2017. The lower ETR in 2018 was largely due to the adjustments above.

Income tax expense decreased $39 million for 2017 compared with 2016. The decrease was primarily driven by increased wind PTCs, a net tax benefit related to the resolution of appeals/audits in 2017, an increase in R&E credits, lower pretax earnings in 2017 and a rise in permanent plant-related adjustments. PTCs are flowed back to customers and reduce electric margin. The decrease was partially offset by the estimated one-time, non-cash, income tax expense recognized in the fourth quarter related to the TCJA. The ETR was 32.1% for 2017 compared with 34.1% for 2016. The lower ETR in 2017 was primarily due to the adjustments referenced above. Excluding the impact for the TCJA adjustment, the ETR would have been 30.7% for 2017.

See Note 7 to the consolidated financial statements for further information.

Xcel Energy Inc. and Other Results

Net income and diluted EPS contributions of Xcel Energy Inc. and its nonregulated businesses:

	Contribution (Millions of Dollars)		
	2018	2017	2016
Xcel Energy Inc. financing costs	$ (110)	$ (79)	$ (71)
Eloigne [(a)]	—	2	1
Xcel Energy Inc. taxes and other results	(5)	(35)	(6)
Total Xcel Energy Inc. and other costs	$ (115)	$ (112)	$ (76)

	Contribution (Diluted Earnings (Loss) Per Share)		
	2018	2017	2016
Xcel Energy Inc. financing costs	$ (0.21)	$ (0.15)	$ (0.14)
Eloigne [(a)]	—	—	—
Xcel Energy Inc. taxes and other results	(0.01)	(0.07)	(0.01)
Total Xcel Energy Inc. and other costs	$ (0.22)	$ (0.22)	$ (0.15)

(a) Amounts include gains or losses associated with sales of properties held by Eloigne.

Xcel Energy Inc.'s results include interest charges, which are incurred at Xcel Energy Inc. and are not directly assigned to individual subsidiaries.

Factors Affecting Results of Operations

Xcel Energy's utility revenues depend on customer usage, which varies with weather conditions, general business conditions and the cost of energy services. Various regulatory agencies approve the prices for electric and natural gas service within their respective jurisdictions and affect Xcel Energy's ability to recover its costs from customers. Historical and future trends of Xcel Energy's operating results have been, and are expected to be, affected by a number of factors, including those listed below.

Regulation

FERC and State Regulation — The FERC and various state and local regulatory commissions regulate Xcel Energy Inc.'s utility subsidiaries and WGI. The electric and natural gas rates charged to customers of Xcel Energy Inc.'s utility subsidiaries and WGI are approved by the FERC or the regulatory commissions in the states in which they operate. The rates are designed to recover plant investment, operating costs and an allowed return on investment. Xcel Energy Inc.'s utility subsidiaries request changes in rates for utility services through filings with governing commissions. Changes in operating costs can affect Xcel Energy's financial results, depending on the timing of rate case filings and implementation of final rates. Other factors affecting rate filings are new investments, sales, conservation and DSM efforts, and the cost of capital. In addition, the regulatory commissions authorize the ROE, capital structure and depreciation rates in rate proceedings. Decisions by these regulators can significantly impact Xcel Energy's results of operations.

Tax Reform — Regulatory Proceedings

In December 2017, the TCJA was signed into law, enacting significant changes to the IRC, including a reduction of the corporate income tax rate from 35% to 21% and a resulting reduction in deferred tax assets and liabilities. As a result of IRS requirements and past regulatory treatment of income taxes in the determination of regulated rates, the impacts of TCJA are primarily recognized as a regulatory liability. Treatment of these tax benefits, (e.g., degree to which benefits will be used to refund currently effective rates and/or used to mitigate other costs and potential future rate increases) is subject to regulatory approval.

Concluded and ongoing regulatory TCJA proceedings:

Operating Company	Utility Service	Approval Date	Additional Information
NSP-Minnesota	Electric and Natural Gas	August 2018	*Minnesota* — In 2018, the MPUC ordered NSP-Minnesota to refund the 2018 impacts of TCJA, including $135 million to electric customers and low income program funding, and $6 million to natural gas customers.
NSP-Minnesota	Electric	July 2018	*South Dakota* — In July 2018, the SDPUC approved a settlement providing a one-time customer refund of $11 million for the 2018 impact of the TCJA, while NSP-Minnesota would retain the TCJA benefits in 2019 and 2020 in exchange for a two-year rate case moratorium.
NSP-Minnesota	Natural Gas	November 2018	*North Dakota* — In November 2018, the NDPSC approved a TCJA settlement in which NSP-Minnesota will amortize $1 million annually of the regulatory asset for the remediation of the MGP site in Fargo, ND and retain the TCJA savings to offset the MGP amortization expense.
NSP-Minnesota	Electric	February 2019	*North Dakota* — In February 2019, the NDPSC approved a settlement including a one-time customer refund of $10 million for 2018, while NSP-Minnesota would retain the TCJA benefits in 2019 and 2020 in exchange for a two-year rate case moratorium.
NSP-Wisconsin	Electric and Natural Gas	May 2018	Wisconsin — In May 2018, the PSCW approved customer refunds of $27 million and deferrals of approximately $5 million until NSP-Wisconsin's next rate case proceeding.
NSP-Wisconsin	Electric and Natural Gas	May 2018	*Michigan* — In May 2018, the MPSC approved electric and natural gas TCJA settlement agreements. Most of the electric TCJA benefits were reflected in NSP-Wisconsin's approved Michigan 2018 electric base rate case.
PSCo	Natural Gas	December 2018	In February 2018, the ALJ recommended approval of a TCJA settlement agreement, which included a $20 million reduction to PSCo's provisional rates effective March 1, 2018. In September 2018, PSCo revised its 2018 TCJA benefit estimate to $24 million and requested an equity ratio of 56% to offset the negative impact of the TCJA on credit metrics. In December 2018, the CPUC approved an equity ratio of 54.6% and utilized the remainder of the TCJA benefit to reduce an existing prepaid pension asset. The CPUC also ordered 2018 excess non-plant ADIT benefits of $11.1 million be utilized to accelerate amortization of the prepaid pension asset.
PSCo	Electric	June 2018 October 2018	In 2018, the CPUC approved a TCJA settlement agreement that included a customer refund of $42 million in 2018, with the remainder of the $59 million of TCJA benefits to be used to accelerate the amortization of an existing prepaid pension asset. For 2019, the expected customer refund is estimated to be $67 million, and amortization of the prepaid pension asset is estimated to be $34 million. Impacts of the TCJA for 2020 and future years are expected to be addressed in a future electric rate case.
SPS	Electric	December 2018	*Texas* - In December 2018, the PUCT approved a rate settlement which fully reflects the TCJA cost impacts and results in no change in customer rates or refunds and SPS' actual capital structure, which SPS has informed the parties it intends to be up to a 57% equity ratio to offset the negative impacts on its credit metrics and potentially its credit ratings.
SPS	Electric	Pending	*New Mexico* - In September 2018, the NMPRC issued its final order in SPS' 2017 electric rate case, which included a $10 million refund of the 2018 impact of the TCJA. SPS subsequently filed an appeal with the NMSC, including the order to refund retroactive TCJA savings. The NMSC granted a temporary stay to delay the implementation of the retroactive TCJA refund until a decision on the appeal occurs. On Feb. 15, 2019, SPS and the NMPRC filed a Joint Motion to Dismiss with the NMSC, requesting they remand the case back to the NMPRC to provide them the opportunity to revise its rate case order in accordance with the motion. This would require the NMPRC to replace the order issued in September 2018 and eliminate the retroactive TCJA refund. The revised order would be subject to further administrative or judicial review.

See Note 7 to the consolidated financial statements for further information.

Pending and Recently Concluded Regulatory Proceedings

Mechanism	Utility Service	Amount Requested (in millions)	Filing Date	Approval	Additional Information
					NSP-Minnesota (MPUC)
TCR	Electric	$98	November 2017	Pending	Reflects the revenue requirements for 2018 and a true-up for 2017 and is based on a proposed ROE of 10%. The MPUC decision is expected during the first quarter of 2019.
CIP Incentive	Electric & Natural Gas	$34	March 2018	Received	The MPUC approved 2017 CIP electric and natural gas financial incentives, effective October 2018, of $30 million and $4 million, respectively.
CIP Rider	Electric & Natural Gas	$57	March 2018	Received	The MPUC approved the forecasted 2018 electric and natural gas CIP riders with estimated 2019 recovery of $48 million and $9 million of electric and natural gas CIP expenses, respectively.
2018 GUIC	Natural Gas	$23	November 2017	Pending	Proposed ROE of 10%. The MPUC decision is expected during the first quarter of 2019.
2019 GUIC	Natural Gas	$29	November 2018	Pending	Proposed ROE of 10.25%. Timing of the MPUC decision is uncertain.
RDF	Electric	$42	October 2018	Received	The MPUC approved the 2019 RDF rate based on a net revenue requirement of $42 million, effective January 2019.
RES	Electric	$23	November 2017	Pending	Reflects the revenue requirements for 2018, 2017 true-up and a proposed ROE of 10%. The MPUC decision is expected in the first quarter of 2019.
					PSCo (CPUC)
Multi-Year Rate Case	Natural Gas	$139	June 2017	Received	Proposed annual revenue request of $139 million over three years, $63 million for 2018. Requested an ROE of 10.0% and an equity ratio of 55.25%. In August 2018, CPUC approved an increase of $46 million (prior to TCJA impacts). The interim decision included application of a 2016 HTY, a 13-month average rate base, an ROE of 9.35%, an equity ratio of 54.6% and provided no return on the prepaid pension asset. In December 2018, the CPUC issued the final ruling which upheld the interim decision and finalized the TCJA impacts.
					In October 2018, the CPUC approved a settlement to extend the PSIA rider through 2021.
DSM Incentive	Electric & Natural Gas	$11	April 2018	Received	PSCo earned an electric and natural gas DSM incentive of $9 million and $2 million, respectively, for achieving its 2017 savings goals.
					SPS (PUCT)
Rate Case	Electric	$54	August 2017	Received	In 2017, SPS filed a retail electric, non-fuel base rate increase case in Texas, which included an ROE of 9.5%. In December 2018, PUCT issued a final order approving a settlement, which results in no overall change to SPS' revenues after adjusting for the impact of the TCJA and the lower costs of long-term debt. In November 2018, SPS filed an application with the PUCT requesting permission to recover $5.4 million in unbilled TCRF revenue from January 23, 2018 through June 9, 2018. Timing of a final order on this matter is uncertain.
					SPS (NMPRC)
Rate Case	Electric	$41	November 2016	Pending	In 2017, SPS filed a notice of appeal to the New Mexico Supreme Court. A decision is not expected until the second half of 2019.
Rate Case	Electric	$43	October 2017	Received/ Pending	In September 2018, the NMPRC approved a revenue increase of approximately $8 million, effective Sept. 27, 2018, based on a ROE of 9.1% and a 51% equity ratio. The NMPRC also ordered a refund of $10 million associated with the TCJA impacts (retroactive Jan. 1, 2018 - Sept. 27, 2018). SPS recorded a regulatory liability for this amount in the third quarter of 2018. SPS subsequently filed an appeal of the order. The NMSC subsequently granted a temporary stay to delay the implementation of the retroactive TCJA refund until a decision on the appeal occurs. On Feb. 15, 2019, SPS and the NMPRC filed a Joint Motion to Dismiss with the NMSC, requesting they remand the case back to the NMPRC to provide them the opportunity to revise its rate case order in accordance with the motion. This would require the NMPRC to replace the order issued in September 2018 with the following: eliminating the retroactive refund associated with the TCJA, approving a ROE of 9.56% and approving an equity ratio of 53.97%. Annual revenue increase based on terms of the settlement agreement would be $12.5 million ($8 million from original order plus $4.5 million for changes in ROE and equity ratio). New rates would be effective as of the date provided by the revised NMPRC order (not retrospective to Sept. 26, 2018), which is expected in the second quarter of 2019. The revised order would be subject to further administrative or judicial review.

See Rate Matters within Note 12 to the consolidated financial statements for further information.

NSP-Minnesota — Mankato Energy Center Acquisition — In November 2018, NSP-Minnesota reached an agreement with Southern Power Company to purchase the 760 MW natural gas combined cycle Mankato Energy Center for approximately $650 million. NSP-Minnesota previously contracted to purchase the energy and capacity of this facility through a PPA. The asset acquisition is anticipated to close in mid-2019 and subject to regulatory approvals from the MPUC, NDPSC, FERC and DOJ. The acquisition is projected to provide net customer savings of approximately $50 million to $150 million over the life of the plant.

NSP-Minnesota — Wind Repowering Acquisition — In December 2018, NSP-Minnesota filed with the MPUC to acquire the Jeffers and Community Wind North wind farms from Longroad Energy. The wind farms will have approximately 70 MW of capacity after being repowered. The repowering is expected to be completed by December 2020 to qualify for the 100% PTC benefit. The acquisition is projected to provide customer savings of approximately $7 million over the life of the wind farms. Cost of acquisition is approximately $135 million and pending MPUC approval.

General Economic Conditions

Economic conditions may have a material impact on Xcel Energy's operating results. Other events impact overall economic conditions and management cannot predict the impact of fluctuating energy prices, terrorist activity, war or the threat of war. However, Xcel Energy could experience a material impact to its results of operations, future growth or ability to raise capital resulting from a sustained general slowdown in economic growth or a significant increase in interest rates.

Fuel Supply and Costs

See Item 1 — Fuel Supply and Costs for discussion of fuel supply and costs.

Pension Plan Costs and Assumptions

Xcel Energy has significant net pension and postretirement benefit costs that are measured using actuarial valuations. Key assumptions in these valuations include discount rates and expected return on plan assets. Xcel Energy evaluates these key assumptions at least annually by analyzing current market conditions, which include changes in interest rates and market returns. Changes in the related net pension and postretirement benefits costs and funding requirements may occur in the future due to changes in assumptions. The payout of a significant percentage of pension plan liabilities in a single year due to high retirements or employees leaving Xcel Energy would trigger settlement accounting and could require Xcel Energy to recognize material incremental pension expense related to unrecognized plan losses in the year these liabilities are paid. For further discussion and a sensitivity analysis on these assumptions, see "Employee Benefits" under Critical Accounting Policies and Estimates.

Environmental Matters

Environmental costs include accruals for nuclear plant decommissioning and payments for storage of spent nuclear fuel, disposal of hazardous materials and waste, remediation of contaminated sites, monitoring of discharges to the environment and compliance with laws and permits with respect to emissions.

Costs charged to operating expenses for nuclear decommissioning and spent nuclear fuel disposal expenses, environmental monitoring and disposal of hazardous materials and waste were approximately:

- $309 million in 2018;
- $303 million in 2017; and,
- $304 million in 2016.

Xcel Energy estimates an average annual expense of approximately $356 million from 2019 - 2023 for similar costs. The precise timing and amount of environmental costs, including those for site remediation and disposal of hazardous materials, are unknown. Additionally, the extent to which environmental costs will be included in and recovered through rates may fluctuate.

Capital expenditures for environmental improvements at regulated facilities were approximately:

- $50 million in 2018;
- $61 million in 2017; and,
- $93 million in 2016.

See Item 7 — Capital Requirements for further discussion.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Preparation of the consolidated financial statements and disclosures in compliance with GAAP requires the application of accounting rules and guidance, as well as the use of estimates. Application of these policies involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges and anticipated recovery of costs. These judgments could materially impact the consolidated financial statements and disclosures, based on varying assumptions. In addition, the financial and operating environment also may have a significant effect on the operation of the business and results reported.

Accounting policies and estimates that are most significant to Xcel Energy's results of operations, financial condition or cash flows, and require management's most difficult, subjective or complex judgments are outlined below. Each of these has a higher likelihood of resulting in materially different reported amounts under different conditions or using different assumptions. Each critical accounting policy has been reviewed and discussed with the Audit Committee of Xcel Energy Inc.'s Board of Directors on a quarterly basis.

Regulatory Accounting

Xcel Energy Inc. is subject to the accounting for Regulated Operations, which provides that rate-regulated entities report assets and liabilities consistent with the recovery of those incurred costs in rates, if it is probable that such rates will be charged and collected. Xcel Energy's rates are derived through the ratemaking process, which results in the recording of regulatory assets and liabilities based on the probability of future cash flows. Regulatory assets generally represent incurred or accrued costs that have been deferred because future recovery from customers is probable. Regulatory liabilities generally represent amounts that are expected to be refunded to customers in future rates or amounts collected in current rates for future costs. In other businesses or industries, regulatory assets and regulatory liabilities would generally be charged to net income or other comprehensive income.

Each reporting period Xcel Energy assesses the probability of future recoveries and obligations associated with regulatory assets and liabilities. Factors such as the current regulatory environment, recently issued rate orders and historical precedents are considered. Decisions made by regulatory agencies can directly impact the amount and timing of cost recovery as well as the rate of return on invested capital, and may materially impact Xcel Energy's results of operations, financial condition or cash flows.

As of Dec. 31, 2018 and 2017, Xcel Energy has recorded regulatory assets of $3.8 billion and $3.4 billion, respectively, and regulatory liabilities of $5.6 billion and $5.3 billion, respectively. Each subsidiary is subject to regulation that varies from jurisdiction to jurisdiction. If future recovery of costs in any such jurisdiction is no longer probable, Xcel Energy would be required to charge these assets to current net income or other comprehensive income. In assessing the probability of recovery of recognized regulatory assets, Xcel Energy noted no current or anticipated proposals or changes in the regulatory environment that it expects will materially impact the probability of recovery of the assets.

See Note 4 to the consolidated financial statements for further information.

Income Tax Accruals

Judgment, uncertainty and estimates are a significant aspect of the income tax accrual process that accounts for the effects of current and deferred income taxes. Uncertainty associated with the application of tax statutes and regulations and outcomes of tax audits and appeals require that judgment and estimates be made in the accrual process and in the calculation of the ETR.

Changes in tax laws and rates may affect recorded deferred tax assets and liabilities and our future ETR. ETR calculations are revised every quarter based on best available year-end tax assumptions, adjusted in the following year after returns are filed. The tax accrual estimates being trued-up to the actual amounts claimed on the tax returns and further adjusted after examinations by taxing authorities, as needed.

In accordance with the interim period reporting guidance, income tax expense for the first three quarters in a year is based on the forecasted annual ETR. The forecasted ETR reflects a number of estimates including forecasted annual income, permanent tax adjustments and tax credits.

Valuation allowances are applied to deferred tax assets if it is more likely than not that at least a portion may not be realized based on an evaluation of expected future taxable income. Accounting for income taxes also requires that only tax benefits that meet the more likely than not recognition threshold can be recognized or continue to be recognized. We may adjust our unrecognized tax benefits and interest accruals as disputes with the IRS and state tax authorities are resolved, and as new developments occur. These adjustments may increase or decrease earnings.

See Note 7 to the consolidated financial statements for further information.

Employee Benefits

Xcel Energy sponsors several noncontributory, defined benefit pension plans and other postretirement benefit plans that cover almost all employees and certain retirees. Projected benefit costs are based on historical information and actuarial calculations that include a number of key assumptions (e.g., annual return level on pension and postretirement health care investment assets, discount rates, mortality rates and health care cost trend rates). In addition, the pension cost calculation uses an asset-smoothing methodology to reduce the volatility of investment performance over time. Pension assumptions are continually reviewed by Xcel Energy..

At Dec. 31, 2018, Xcel Energy set the rate of return on assets used to measure pension costs at 6.87%, which is consistent with the rate set at Dec. 31, 2017. The rate of return used to measure postretirement health care costs is 5.30% at Dec. 31, 2018, which represents a 50 basis point decrease from Dec. 31, 2017. Xcel Energy's pension investment strategy is based on plan-specific investments that seek to minimize investment and interest rate risk as a plan's funded status increases over time. This strategy results in a greater percentage of interest rate sensitive securities being allocated to plans having relatively higher funded status ratios and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios.

Xcel Energy set the discount rates used to value the pension obligations at 4.31% and postretirement health care obligations at 4.32% at Dec. 31, 2018. This represents a 68 basis point and 70 basis point increase, respectively, from Dec. 31, 2017. Xcel Energy uses a bond matching study as its primary basis for determining the discount rate used to value pension and postretirement health care obligations. The bond matching study utilizes a portfolio of high grade (Aa or higher) bonds that matches the expected cash flows of Xcel Energy's benefit plans in amount and duration.

The effective yield on this cash flow matched bond portfolio determines the discount rate for the individual plans. The bond matching study is validated for reasonableness against the Merrill Lynch Corporate 15+ Bond Index. In addition, Xcel Energy reviews general actuarial survey data to assess the reasonableness of the discount rate selected.

If Xcel Energy were to use alternative assumptions at Dec. 31, 2018, a 1% change would result in the following impact on 2018 pension costs:

	Pension Costs	
(Millions of Dollars)	+1%	-1%
Rate of return	$ (17)	$ 17
Discount rate [(a)]	(6)	7

(a) These costs include the effects of regulation.

Mortality rates are developed from actual and projected plan experience for pension plan and postretirement benefits. Xcel Energy's actuary conducts an experience study periodically as part of the process to determine an estimate of mortality. Xcel Energy considers standard mortality tables, improvement factors and the plans actual experience when selecting a best estimate.

As of Dec. 31, 2018 the initial medical trend cost claim assumptions for Pre-65 was 6.5% and Post-65 was 5.3%. The ultimate trend assumption remained at 4.5% for both Pre-65 and Post-65 claims costs. The period from initial trend rate until the ultimate rate is reached is four years. Xcel Energy bases its medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost experienced by Xcel Energy's retiree medical plan.

A 1% change in the assumed health care cost trend rate would have the following effects on Xcel Energy:

	APBO		Service and Interest Components	
(Millions of Dollars)	+1%	-1%	+1%	-1%
Health care cost trend	$ 49	$ (42)	$ 3	$ (2)

Funding requirements in 2019 are expected to remain consistent with 2018, continue at that level in 2020 and begin to decline in the following years. While investment returns were below the assumed levels in 2016 and exceeded assumed levels in 2017, investment returns were below the assumed levels in 2018.

The pension cost calculation uses a market-related valuation of pension assets. Xcel Energy uses a calculated value method to determine the market-related value of the plan assets. The market-related value is determined by adjusting the fair market value of assets at the beginning of the year to reflect the investment gains and losses (the difference between the actual investment return and the expected investment return on the market-related value) during each of the previous five years at the rate of 20% per year. As differences between actual and expected investment returns are incorporated into the market-related value, amounts are recognized in pension cost over the expected average remaining years of service for active employees (approximately 13 years in 2018).

Xcel Energy currently projects the pension costs recognized for financial reporting purposes will be $114 million in 2019 and $107 million in 2020, while the actual pension costs were $140 million in 2018 and $139 million in 2017. The expected decrease in 2019 and future year costs is primarily due the settlement charge experienced in 2018 and reductions in loss amortizations.

Pension funding contributions across all four of Xcel Energy's pension plans, both voluntary and required, for 2016 - 2019:

- $150 million in January 2019;
- $150 million in 2018;
- $162 million in 2017; and,
- $125 million in 2016

Future amounts may change based on actual market performance, changes in interest rates and any changes in governmental regulations. Therefore, additional contributions could be required in the future.

Xcel Energy contributed $11 million, $20 million and $18 million during 2018, 2017 and 2016, respectively, to the postretirement health care plans. Xcel Energy expects to contribute approximately $11 million during 2019.

Xcel Energy recovers employee benefits costs in its utility operations consistent with accounting guidance with the exception of the areas noted below.

- NSP-Minnesota recognizes pension expense in all regulatory jurisdictions using the aggregate normal cost actuarial method. Differences between aggregate normal cost and expense as calculated by pension accounting standards are deferred as a regulatory liability.
- In 2018, the PSCW approved NSP-Wisconsin's request for deferred accounting treatment of the 2018 pension settlement accounting expense.
- Regulatory Commissions in Colorado, Texas, New Mexico and FERC jurisdictions allow the recovery of other postretirement benefit costs only to the extent that recognized expense is matched by cash contributions to an irrevocable trust. Xcel Energy has consistently funded at a level to allow full recovery of costs in these jurisdictions.
- PSCo and SPS recognize pension expense in all regulatory jurisdictions based on expense consistent with accounting guidance. The Texas and Colorado electric retail jurisdictions and the Colorado gas retail jurisdiction, each record the difference between annual recognized pension expense and the annual amount of pension expense approved in their last respective general rate case as a deferral to a regulatory asset.
- In 2018, PSCo was required to create a regulatory liability to adjust postretirement health care costs to zero in order to match the amounts collected in rates in the Colorado Gas retail jurisdiction.

See Note 11 to the consolidated financial statements for further information.

Nuclear Decommissioning

Xcel Energy recognizes liabilities for the expected cost of retiring tangible long-lived assets for which a legal obligation exists. These AROs are recognized at fair value as incurred and are capitalized as part of the cost of the related long-lived assets. In the absence of quoted market prices, Xcel Energy estimates the fair value of its AROs using present value techniques, in which it makes assumptions including estimates of the amounts and timing of future cash flows associated with retirement activities, credit-adjusted risk free rates and cost escalation rates. When Xcel Energy revises any assumptions, it adjusts the carrying amount of both the ARO liability and related long-lived asset. ARO liabilities are accreted to reflect the passage of time using the interest method.

A significant portion of Xcel Energy's AROs relates to the future decommissioning of NSP-Minnesota's nuclear facilities. The nuclear decommissioning obligation is funded by the external decommissioning trust fund. Difference between regulatory funding (including depreciation expense less returns from the external trust fund) and expense recognized is deferred as a regulatory asset. The amounts recorded for AROs related to future nuclear decommissioning were $1.968 billion in 2018 and $1.874 billion in 2017.

NSP-Minnesota obtains periodic independent cost studies in order to estimate the cost and timing of planned nuclear decommissioning activities. Estimates of future cash flows are highly uncertain and may vary significantly from actual results. NSP-Minnesota is required to file a nuclear decommissioning filing every three years. The filing covers all expenses for the decommissioning of the nuclear plants, including decontamination and removal of radioactive material.

The most recent triennial filing was approved by the MPUC in January 2019 and resulted in no change to the accrual. The 2020 accrual will be set subsequent to a compliance filing that is expected to be submitted in July 2019.

The following assumptions have a significant effect on the estimated nuclear obligation:

Timing — Decommissioning cost estimates are impacted by each facility's retirement date and timing of the actual decommissioning activities. Estimated retirement dates coincide with the expiration of each unit's operating license with the NRC (i.e., 2030 for Monticello and 2033 and 2034 for PI's Unit 1 and 2, respectively). The estimated timing of the decommissioning activities is based upon the DECON method, which assumes prompt removal and dismantlement. The use of the DECON method is required by the MPUC. Decommissioning activities are expected to begin at the end of the license date and be completed for both facilities by 2091.

Technology and Regulation — There is limited experience with actual decommissioning of large nuclear facilities. Changes in technology, experience and regulations could cause cost estimates to change significantly.

Escalation Rates — Escalation rates represent projected cost increases due to general inflation and increases in the cost of decommissioning activities. NSP-Minnesota used an escalation rate of 3.4% in calculating the ARO for nuclear decommissioning of its nuclear facilities, based on the weighted averages of labor and non-labor escalation factors calculated by Goldman Sachs Asset Management.

Discount Rates — Changes in timing or estimated cash flows that result in upward revisions to the ARO are calculated using the then-current credit-adjusted risk-free interest rate. The credit-adjusted risk-free rate in effect when the change occurs is used to discount the revised estimate of the incremental expected cash flows of the retirement activity. If the change in timing or estimated expected cash flows results in a downward revision of the ARO, the undiscounted revised estimate of expected cash flows is discounted using the credit-adjusted risk-free rate in effect at the date of initial measurement and recognition of the original ARO. Discount rates ranging from approximately 4% to 7% have been used to calculate the net present value of the expected future cash flows over time.

Significant uncertainties exist in estimating future costs including the method to be utilized, ultimate costs to decommission and planned method of disposing spent fuel. If different cost estimates, life assumptions or cost escalation rates were utilized, the AROs could change materially. However, changes in estimates have minimal impact on results of operations as NSP-Minnesota expects to continue to recover all costs in future rates.

Xcel Energy continually makes judgments and estimates related to these critical accounting policy areas, based on an evaluation of the assumptions and uncertainties for each area. The information and assumptions of these judgments and estimates will be affected by events beyond the control of Xcel Energy, or otherwise change over time. This may require adjustments to recorded results to better reflect updated information that becomes available. The accompanying financial statements reflect management's best estimates and judgments of the impact of these factors as of Dec. 31, 2018.

See Note 12 to the consolidated financial statements for further information.

Derivatives, Risk Management and Market Risk

Xcel Energy Inc. and its subsidiaries are exposed to a variety of market risks in the normal course of business. Market risk is the potential loss that may occur as a result of adverse changes in the market or fair value of a particular instrument or commodity. All financial and commodity-related instruments, including derivatives, are subject to market risk.

See Note 10 to the consolidated financial statements for further information.

Xcel Energy is exposed to the impact of adverse changes in price for energy and energy-related products, which is partially mitigated by the use of commodity derivatives. In addition to ongoing monitoring and maintaining credit policies intended to minimize overall credit risk, management takes steps to mitigate changes in credit and concentration risks associated with its derivatives and other contracts, including parental guarantees and requests of collateral. While Xcel Energy expects that the counterparties will perform under the contracts underlying its derivatives, the contracts expose Xcel Energy to certain credit and non-performance risk.

Distress in the financial markets may impact counterparty risk, the fair value of the securities in the nuclear decommissioning fund and pension fund and Xcel Energy's ability to earn a return on short-term investments.

Commodity Price Risk — Xcel Energy Inc.'s utility subsidiaries are exposed to commodity price risk in their electric and natural gas operations. Commodity price risk is managed by entering into long- and short-term physical purchase and sales contracts for electric capacity, energy and energy-related products and fuels used in generation and distribution activities. Commodity price risk is also managed through the use of financial derivative instruments. Xcel Energy's risk management policy allows it to manage commodity price risk within each rate-regulated operation per commission approved hedge plans.

Wholesale and Commodity Trading Risk — Xcel Energy Inc.'s utility subsidiaries conduct various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy, energy-related instruments and natural gas-related instruments, including derivatives. Xcel Energy's risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee.

At Dec. 31, 2018, fair values by source for net commodity trading contract assets were as follows:

	Futures / Forwards					
(Millions of Dollars)	Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Futures / Forwards Fair Value
NSP-Minnesota	2	$ 3	$ 5	$ 2	$ 1	$ 11
PSCo	2	1	—	—	—	1
		$ 4	$ 5	$ 2	$ 1	$ 12

	Options					
(Millions of Dollars)	Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Options Fair Value
NSP-Minnesota	2	$ —	$ 4	$ 1	$ —	$ 5

2 — Prices based on models and other valuation methods.

Changes in the fair value of commodity trading contracts before the impacts of margin-sharing for the years ended Dec. 31 were as follows:

(Millions of Dollars)	2018	2017
Fair value of commodity trading net contract assets outstanding at Jan. 1	$ 16	$ 10
Contracts realized or settled during the period	(10)	(5)
Commodity trading contract additions and changes during the period	11	11
Fair value of commodity trading net contract assets outstanding at Dec. 31	$ 17	$ 16

At Dec. 31, 2018, a 10% increase in market prices for commodity trading contracts would increase pretax income by approximately $16 million, whereas a 10% decrease would decrease pretax income by approximately $16 million. At Dec. 31, 2017, a 10% increase or decrease in market prices for commodity trading contracts would have an immaterial impact.

Xcel Energy Inc.'s utility subsidiaries' wholesale and commodity trading operations measure the outstanding risk exposure to price changes on transactions, contracts and obligations using VaR. VaR expresses the potential change in fair value on the outstanding transactions, contracts and obligations over a particular period of time under normal market conditions.

VaRs for the NSP-Minnesota and PSCo commodity trading operations, calculated on a consolidated basis using a Monte Carlo simulation with a 95% confidence level and a one-day holding period:

(Millions of Dollars)	Year Ended Dec. 31	VaR Limit	Average	High	Low
2018	$ 4.83	$ 6.00	$ 0.62	$ 5.63	$ 0.06
2017	0.18	3.00	0.21	0.66	0.04

In November 2018, management temporarily increased the VaR limit to accommodate a 10-year transaction. NSP-Minnesota has been systematically hedging the transaction and the consolidated VaR returned below $3 million in January 2019.

Nuclear Fuel Supply — NSP-Minnesota is scheduled to take delivery of approximately 24% of its 2019 and approximately 54% of its 2020 enriched nuclear material requirements from sources that could be impacted by events in Ukraine and extended sanctions against Russia. Long-term, through 2024, NSP-Minnesota is scheduled to take delivery of approximately 32% of its average enriched nuclear material requirements from these sources. Alternate potential sources provide the flexibility to manage NSP-Minnesota's nuclear fuel supply. NSP-Minnesota periodically assesses if further actions are required to assure a secure supply of enriched nuclear material.

Disruptions in third party nuclear fuel supply contracts due to bankruptcies or change of contract assignments have not materially impacted NSP-Minnesota's operational or financial performance.

Interest Rate Risk — Xcel Energy is subject to interest rate risk. Xcel Energy's risk management policy allows interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate derivatives such as swaps, caps, collars and put or call options.

A 100 basis point change in the benchmark rate on Xcel Energy's variable rate debt would impact annual pretax interest expense by approximately $10 million in 2018 and $9 million in 2017.

NSP-Minnesota maintains a nuclear decommissioning fund, as required by the NRC. The nuclear decommissioning fund is subject to interest rate risk and equity price risk. The fund is invested in a diversified portfolio of cash equivalents, debt securities, equity securities and other investments. These investments may be used only for the purpose of decommissioning NSP-Minnesota's nuclear generating plants.

Realized and unrealized gains on the decommissioning fund investments are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Fluctuations in equity prices or interest rates affecting the nuclear decommissioning fund do not have a direct impact on earnings due to the application of regulatory accounting. See Note 10 to the consolidated financial statements for further information.

Changes in discount rates and expected return on plan assets impact the value of pension and postretirement plan assets as well as benefit costs.

See Note 11 to the consolidated financial statements for further information.

Credit Risk — Xcel Energy Inc. and its subsidiaries are also exposed to credit risk. Credit risk relates to the risk of loss resulting from counterparties' nonperformance on their contractual obligations. Xcel Energy Inc. and its subsidiaries maintain credit policies intended to minimize overall credit risk and actively monitor these policies to reflect changes and scope of operations.

At Dec. 31, 2018, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $14 million, while a decrease in prices of 10% would have resulted in an increase in credit exposure of $3 million. At Dec. 31, 2017, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $26 million, while a decrease in prices of 10% would have resulted in an increase in credit exposure of $7 million.

Xcel Energy Inc. and its subsidiaries conduct credit reviews for all counterparties and employ credit risk controls, such as letters of credit, parental guarantees, master netting agreements and termination provisions. Credit exposure is monitored, and when necessary, the activity with a specific counterparty is limited until credit enhancement is provided. Distress in the financial markets could increase Xcel Energy's credit risk.

Fair Value Measurements

Xcel Energy uses derivative contracts such as futures, forwards, interest rate swaps, options and FTRs to manage commodity price and interest rate risk. Derivative contracts, with the exception of those designated as normal purchase-normal sale contracts, are reported at fair value. Xcel Energy's investments held in the nuclear decommissioning fund, rabbi trusts, pension and other postretirement funds are also subject to fair value accounting.

See Notes 10 and 11 to the consolidated financial statements for further information.

Commodity Derivatives — Xcel Energy monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions. Given the typically short duration of these contracts, the impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at Dec. 31, 2018.

Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric revenues. Credit risk adjustments for other commodity derivative instruments are recorded as other comprehensive income or deferred as regulatory assets and liabilities. Classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. The impact of discounting commodity derivative liabilities for credit risk was immaterial at Dec. 31, 2018.

Liquidity and Capital Resources

Cash Flows

(Millions of Dollars)	2018	2017	2016
Net cash provided by operating activities	$ 3,122	$ 3,126	$ 3,052

Net cash provided by operating activities decreased by $4 million for 2018 as compared to 2017. Change was primarily due to refunds associated with the TCJA and timing of certain electric and natural gas recovery mechanisms, partially offset by the change in net income (excluding amounts related to non-cash operating activities (e.g., depreciation and deferred tax expenses)).

Net cash provided by operating activities increased by $74 million for 2017 as compared to 2016. Increase was primarily due to higher net income, excluding amounts related to non-cash operating activities (e.g., depreciation and deferred tax expenses) and timing of customer receipts, partially offset by higher interest payments and pension contributions, refunds, timing of vendor payments and lower income tax refunds.

(Millions of Dollars)	2018	2017	2016
Net cash used in investing activities	$ (3,986)	$ (3,296)	$ (3,261)

Net cash used in investing activities increased by $690 million for 2018 as compared to 2017. Increase was largely related to higher capital expenditures for the Rush Creek, Foxtail and Hale wind generation facilities.

Net cash used in investing activities increased by $35 million for 2017 as compared to 2016. Increase was mainly attributable to capital expenditures related to the Rush Creek wind generation facility, partially offset by amounts for the Courtenay wind farm and less rabbi trust investments.

(Millions of Dollars)	2018	2017	2016
Net cash provided by financing activities	$ 928	$ 168	$ 209

Net cash provided by financing activities increased by $760 million for 2018 as compared to 2017. Increase was primarily due to lower repayments of long-term debt, proceeds from the issuances of common stock and additional debt financings, partially offset by lower short-term debt proceeds as compared to 2017.

Net cash provided by financing activities decreased by $41 million for 2017 as compared to 2016. Decrease was primarily due to lower proceeds from debt issuances and higher dividend payments, partially offset by higher short-term debt proceeds and lower repurchases of common stock in 2017.

Capital Requirements

Xcel Energy expects to meet future financing requirements by periodically issuing short-term debt, long-term debt, common stock, hybrid and other securities to maintain desired capitalization ratios.

Contractual Obligations and Other Commitments — Xcel Energy has contractual obligations and other commitments that will need to be funded in the future. Contractual obligations and other commercial commitments as of Dec. 31, 2018 were as follows:

		Payments Due by Period			
(Millions of Dollars)	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	After 5 Years
Long-term debt, principal and interest payments	$ 27,538	$ 1,062	$ 2,910	$ 2,711	$ 20,855
Capital lease obligations	286	14	28	24	220
Operating leases [(a)]	2,174	239	469	429	1,037
Unconditional purchase obligations [(b)]	6,700	1,457	1,990	1,432	1,821
Other long-term obligations, including current portion	716	57	98	64	497
Other short-term obligations	405	405	—	—	—
Short-term debt	1,038	1,038	—	—	—
Total contractual cash obligations	$ 38,857	$ 4,272	$ 5,495	$ 4,660	$ 24,430

(a) Included in operating lease payments are $207 million, $418 million, $383 million and $0.9 billion, for the less than 1 year, 1 - 3 years, 3 - 5 years and after 5 years categories, respectively, pertaining to PPAs that were accounted for as operating leases.

(b) Xcel Energy Inc. and its subsidiaries have contracts providing for the purchase and delivery of a significant portion of its coal, nuclear fuel and natural gas requirements. Additionally, the utility subsidiaries of Xcel Energy Inc. have entered into non-lease purchase power agreements. Certain contractual purchase obligations are adjusted on indices. Effects of price changes are mitigated through cost of energy adjustment mechanisms.

See Notes 5 and 12 to the consolidated financial statements for further information.

Capital Expenditures — Current estimated base capital expenditure programs of Xcel Energy's operating companies for the years 2019 - 2023:

	Capital Forecast					
(Millions of Dollars)	2019	2020	2021	2022	2023	2019 - 2023 Total
By Subsidiary						
NSP-Minnesota	$ 2,825	$ 1,290	$ 1,540	$ 1,300	$ 1,380	$ 8,335
PSCo	1,370	1,380	1,335	1,395	1,530	7,010
SPS	1,130	770	460	530	635	3,525
NSP-Wisconsin	240	240	300	305	275	1,360
Other [(a)]	(50)	(70)	(25)	10	15	(120)
Total capital expenditures	$ 5,515	$ 3,610	$ 3,610	$ 3,540	$ 3,835	$ 20,110

	Capital Forecast					
(Millions of Dollars)	2019	2020	2021	2022	2023	2019 - 2023 Total
By Function						
Electric distribution	$ 775	$ 865	$ 1,150	$ 1,245	$ 1,270	$ 5,305
Electric transmission	580	560	950	870	1,055	4,015
Renewables	2,315	1,105	240	—	—	3,660
Electric generation	1,070	310	480	560	545	2,965
Natural gas	430	415	420	510	595	2,370
Other [(b)]	345	355	370	355	370	1,795
Total capital expenditures	$ 5,515	$ 3,610	$ 3,610	$ 3,540	$ 3,835	$ 20,110

(a) Other category includes intercompany transfers for safe harbor wind turbines.

(b) Amounts in other category are net of intercompany transfers.

Xcel Energy's capital expenditure program is subject to continuous review and modification. Actual capital expenditures may vary from estimates due to changes in electric and natural gas projected load growth, regulatory decisions, legislative initiatives, reserve margin requirements, availability of purchased power, alternative plans for meeting long-term energy needs, compliance with environmental requirements, RPS and merger, acquisition and divestiture opportunities.

Xcel Energy issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund capital programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes.

Financing Capital Expenditures through 2023 — Xcel Energy issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund capital programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes. Current estimated financing plans of Xcel Energy for 2019 - 2023:

(Millions of Dollars)	
Funding Capital Expenditures	
Cash from Operations*	$ 13,070
New Debt**	6,190
Equity through the DRIP and Benefit Program	390
Equity through forward equity agreements	460
Base Capital Expenditures 2019 - 2023	$ 20,110
Maturing Debt	$ 3,645

* Net of dividends and pension funding.

** Reflects a combination of short and long-term debt; net of refinancing.

Common Stock Dividends — Future dividend levels will be dependent on Xcel Energy's results of operations, financial condition, cash flows, reinvestment opportunities and other factors, and will be evaluated by the Xcel Energy Inc. Board of Directors. In February 2019, Xcel Energy announced a quarterly dividend of $0.405 per share, which represents an increase of 6.6%. Xcel Energy's dividend policy balances the following:

- Projected cash generation;
- Projected capital investment;
- A reasonable rate of return on shareholder investment; and,
- The impact on Xcel Energy's capital structure and credit ratings.

In addition, there are certain statutory limitations that could affect dividend levels. Federal law places limits on the ability of public utilities within a holding company system to declare dividends. Specifically, under the Federal Power Act, a public utility may not pay dividends from any funds properly included in a capital account. The utility subsidiaries' dividends may be limited directly or indirectly by state regulatory commissions or bond indenture covenants.

See Note 5 to the consolidated financial statements for further information.

Pension Fund — Xcel Energy's pension assets are invested in a diversified portfolio of domestic and international equity securities, short-term to long-duration fixed income securities and alternative investments, including private equity, real estate and hedge funds. Funded status and pension assumptions:

(Millions of Dollars)	Dec. 31, 2018	Dec. 31, 2017
Fair value of pension assets	$ 2,742	$ 3,088
Projected pension obligation [(a)]	3,477	3,828
Funded status	$ (735)	$ (740)

(a) Excludes non-qualified plan of $33 million and $37 million at Dec. 31, 2018 and 2017, respectively.

Pension Assumptions	2018	2017
Discount rate	4.31%	3.63%
Expected long-term rate of return	6.87	6.87

Capital Sources

Short-Term Funding Sources — Xcel Energy uses a number of sources to fulfill short-term funding needs, including operating cash flow, notes payable, commercial paper and bank lines of credit. The amount and timing of short-term funding needs depend on financing needs for construction expenditures, working capital and dividend payments.

Short-Term Investments — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS maintain cash operating and short-term investment accounts.

Short-Term Debt — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS each have individual commercial paper programs. Authorized levels for these commercial paper programs are:

- $1 billion for Xcel Energy Inc.;
- $700 million for PSCo;
- $500 million for NSP-Minnesota;
- $400 million for SPS; and,
- $150 million for NSP-Wisconsin.

In addition, Xcel Energy Inc. has a 364-day term loan agreement to borrow up to $500 million. As of Dec. 31, 2018, $250 million of borrowings were outstanding with $250 million additional borrowing capacity. In February 2019, Xcel Energy borrowed the remaining $250 million. No additional borrowing capacity currently remains.

Xcel Energy's outstanding short-term debt:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2018
Borrowing limit	$ 3,250
Amount outstanding at period end	1,038
Average amount outstanding	500
Maximum amount outstanding	1,038
Weighted average interest rate, computed on a daily basis	2.76%
Weighted average interest rate at end of period	2.97

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31, 2018	Year Ended Dec. 31, 2017	Year Ended Dec. 31, 2016
Borrowing limit	$ 3,250	$ 3,250	$ 2,750
Amount outstanding at period end	1,038	814	392
Average amount outstanding	788	644	485
Maximum amount outstanding	1,349	1,247	1,183
Weighted average interest rate, computed on a daily basis	2.34%	1.35%	0.74%
Weighted average interest rate at end of period	2.97	1.90	0.95

Credit Facility Agreements — Xcel Energy Inc., NSP-Minnesota, PSCo and SPS each have the right to request an extension of the revolving credit facility for two additional one-year periods beyond the June 2021 termination date. NSP-Wisconsin has the right to request an extension of the revolving credit facility termination date for an additional one-year period. All extension requests are subject to majority bank group approval.

As of Feb. 20, 2019, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet liquidity needs:

(Millions of Dollars)	Facility	Drawn [(a)]	Available	Cash	Liquidity
Xcel Energy Inc.	$ 1,500	$ 786	$ 714	$ —	$ 714
PSCo	700	224	476	1	477
NSP-Minnesota	500	152	348	1	349
SPS	400	128	272	—	272
NSP-Wisconsin	150	29	121	1	122
Total	$ 3,250	$ 1,319	$ 1,931	$ 3	$ 1,934

(a) Includes outstanding commercial paper, term loan borrowings and letters of credit.

Registration Statements — Xcel Energy Inc.'s Articles of Incorporation authorize the issuance of one billion shares of $2.50 par value common stock. As of Dec. 31, 2018 and 2017, Xcel Energy Inc. had approximately 514 million shares and 508 million shares of common stock outstanding, respectively.

Xcel Energy Inc. and its utility subsidiaries have registration statements on file with the SEC pursuant to which they may sell securities from time to time. These registration statements, which are uncapped, permit Xcel Energy Inc. and its utility subsidiaries to issue debt and other securities in the future at amounts, prices and with terms to be determined at the time of future offerings, and in the case of our utility subsidiaries, subject to commission approval.

Planned Financing Activity — Xcel Energy Inc. and its utility subsidiaries' 2019 financing plans reflect the following:

- Xcel Energy Inc. — approximately $700 million of senior notes and approximately $75 to $80 million of equity through the DRIP and benefit programs;
- NSP-Minnesota — approximately $900 million of first mortgage bonds;
- PSCo — approximately $800 million of first mortgage bonds; and,
- SPS — approximately $300 million of first mortgage bonds.

Forward Equity Agreements — In November 2018, Xcel Energy Inc. entered into forward sale agreements in connection with a completed $459 million public offering of 9.4 million shares of Xcel Energy common stock. The initial forward agreement was for 8.1 million shares with an additional forward agreement of 1.2 million shares exercised at the option of the banking counterparty. At Dec. 31, 2018, the forward agreements could have been settled with physical delivery of 9.4 million common shares to the banking counterparty in exchange for cash of $456 million. The forward instruments could also have been settled at Dec. 31, 2018 with delivery of approximately $24 million of cash or approximately 0.5 million shares of common stock to the banking counterparty, if Xcel Energy unilaterally elected net cash or net share settlement, respectively.

The forward price used to determine amounts due at settlement is calculated based on the November 2018 public offering price for Xcel Energy's common stock of $49.00, increased for the overnight bank funding rate, less a spread of 0.75% and less expected dividends on Xcel Energy's common stock during the period the instruments are outstanding.

Xcel Energy may settle the forward agreements at any time up to the maturity date of February 7, 2020. The cash proceeds, depending on the timing of settlement, are expected to be approximately $450 million to $460 million.

Forward equity instruments were accounted for as stockholders' equity and recorded at fair value at the execution of the forward agreements, and will not be subsequently adjusted for changes in fair value until settlement.

ATM Equity Offering — In 2018, Xcel Energy issued 4.7 million shares of common stock with net proceeds of $224.7 million through the at the market program. In addition, total transaction fees of $1.9 million were paid. In November 2018, the ATM offering was closed.

Other Equity — Xcel Energy also plans to issue approximately $75 to $80 million of equity, each year, through the DRIP and benefit programs during the five-year forecast time period.

Long-Term Borrowings and Other Financing Instruments — See Note 5 to the consolidated financial statements for further information.

Off-Balance-Sheet Arrangements

Xcel Energy does not have any off-balance-sheet arrangements, other than those currently disclosed, that have or are reasonably likely to have a current or future effect on financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

Earnings Guidance

2019 GAAP and ongoing earnings guidance is a range of $2.55 to $2.65 per share.[a] Key assumptions:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns for the year.
- Weather-normalized retail electric sales are projected to be relatively consistent with 2018 levels.
- Weather-normalized retail natural gas sales are projected to be within a range of 0.0% to 1.0% over 2018 levels.
- Capital rider revenue is projected to increase $115 million to $125 million (net of PTCs) over 2018 levels. PTCs are flowed back to customers, primarily through capital riders as reductions to electric margin.
- Purchase capacity costs are expected to decline $25 million to $30 million compared with 2018 levels.
- O&M expenses are projected to be consistent with 2017 levels.
- Depreciation expense is projected to increase approximately $120 million to $130 million over 2018 levels. Depreciation expense includes $34 million for the amortization of a prepaid pension asset at PSCo, which is TCJA related and will not impact earnings.
- Property taxes are projected to increase approximately $15 million to $25 million over 2018 levels.
- Interest expense (net of AFUDC — debt) is projected to increase $90 million to $100 million over 2018 levels.
- AFUDC — equity is projected to decrease approximately $20 million to $30 million from 2018 levels.
- The ETR is projected to be approximately 6% to 8%. The ETR reflects benefits of PTCs which are flowed back to customers through electric margin.
- Assumptions do not include the impact for the upcoming adoption of the new lease accounting standard, effective 2019. Xcel Energy does not expect changes in the accounting for leases to impact earnings, but it may result in variations in certain line items within the statement of income.

(a) Ongoing earnings is calculated using net income and adjusting for certain nonrecurring or infrequent items that are, in management's view, not reflective of ongoing operations. Ongoing earnings could differ from those prepared in accordance with GAAP for unplanned and/or unknown adjustments. Xcel Energy is unable to forecast if any of these items will occur or provide a quantitative reconciliation of the guidance for ongoing EPS to corresponding GAAP EPS.

Item 7A — Quantitative and Qualitative Disclosures About Market Risk

See Item 7, incorporated by reference.

Item 8 — Financial Statements and Supplementary Data

See Item 15-1 for an index of financial statements included herein.

See Note 15 to the consolidated financial statements for further information.

Management Report on Internal Controls Over Financial Reporting

The management of Xcel Energy Inc. is responsible for establishing and maintaining adequate internal control over financial reporting. Xcel Energy Inc.'s internal control system was designed to provide reasonable assurance to Xcel Energy Inc.'s management and board of directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Xcel Energy Inc. management assessed the effectiveness of Xcel Energy Inc.'s internal control over financial reporting as of Dec. 31, 2018. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control — Integrated Framework (2013). Based on our assessment, we believe that, as of Dec. 31, 2018, Xcel Energy Inc.'s internal control over financial reporting is effective at the reasonable assurance level based on those criteria.

Xcel Energy Inc.'s independent registered public accounting firm has issued an audit report on the Xcel Energy Inc.'s internal control over financial reporting. Its report appears herein.

/s/ BEN FOWKE	/s/ ROBERT C. FRENZEL
Ben Fowke	Robert C. Frenzel
Chairman, President and Chief Executive Officer	Executive Vice President, Chief Financial Officer
Feb. 22, 2019	Feb. 22, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Xcel Energy Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Xcel Energy Inc. and subsidiaries (the "Company") as of December 31, 2018 and 2017, the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2018, and the related notes and the schedules listed in the Index at Item 15 (collectively referred to as the "financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO.

Basis for Opinions

The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Controls over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the financial statements included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 22, 2019

We have served as the Company's auditor since 2002.

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(*amounts in millions, except per share data)*

	Year Ended Dec. 31		
	2018	2017	2016
Operating revenues			
Electric	$ 9,719	$ 9,676	$ 9,500
Natural gas	1,739	1,650	1,531
Other	79	78	76
Total operating revenues	11,537	11,404	11,107
Operating expenses			
Electric fuel and purchased power	3,854	3,757	3,718
Cost of natural gas sold and transported	843	823	733
Cost of sales — other	35	34	36
Operating and maintenance expenses	2,352	2,270	2,300
Conservation and demand side management program expenses	290	273	245
Depreciation and amortization	1,642	1,479	1,303
Taxes (other than income taxes)	556	545	532
Total operating expenses	9,572	9,181	8,867
Operating income	1,965	2,223	2,240
Other expense, net	(14)	(10)	(18)
Equity earnings of unconsolidated subsidiaries	35	30	42
Allowance for funds used during construction — equity	108	75	60
Interest charges and financing costs			
Interest charges — includes other financing costs of $25, $24 and $25, respectively	700	663	647
Allowance for funds used during construction — debt	(48)	(35)	(27)
Total interest charges and financing costs	652	628	620
Income before income taxes	1,442	1,690	1,704
Income taxes	181	542	581
Net income	$ 1,261	$ 1,148	$ 1,123
Weighted average common shares outstanding:			
Basic	511	509	509
Diluted	511	509	509
Earnings per average common share:			
Basic	$ 2.47	$ 2.26	$ 2.21
Diluted	2.47	2.25	2.21

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(amounts in millions)

	Year Ended Dec. 31		
	2018	2017	2016
Net income	$ 1,261	$ 1,148	$ 1,123
Other comprehensive income (loss)			
Pension and retiree medical benefits:			
Net pension and retiree medical losses arising during the period, net of tax of $(2), $(2), and $(5), respectively	(6)	(3)	(8)
Amortization of losses included in net periodic benefit cost, net of tax of $3, $5, and $2, respectively	9	7	4
	3	4	(4)
Derivative instruments:			
Net fair value decrease, net of tax of $(2), $0, and $0, respectively	(5)	—	—
Reclassification of losses to net income, net of tax of $1, $2, and $2, respectively	3	3	4
	(2)	3	4
Other comprehensive income	1	7	—
Comprehensive income	$ 1,262	$ 1,155	$ 1,123

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(amounts in millions)

	Year Ended Dec. 31		
	2018	2017	2016
Operating activities			
Net income	$ 1,261	$ 1,148	$ 1,123
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	1,659	1,495	1,319
Nuclear fuel amortization	122	114	117
Deferred income taxes	218	640	587
Allowance for equity funds used during construction	(108)	(75)	(60)
Equity earnings of unconsolidated subsidiaries	(35)	(30)	(42)
Dividends from unconsolidated subsidiaries	37	41	46
Provision for bad debts	42	39	39
Share-based compensation expense	45	57	41
Net realized and unrealized hedging and derivative transactions	22	2	8
Changes in operating assets and liabilities:			
Accounts receivable	(105)	(60)	(83)
Accrued unbilled revenues	9	(34)	(75)
Inventories	(65)	(3)	1
Other current assets	18	9	61
Accounts payable	90	43	118
Net regulatory assets and liabilities	223	(16)	(19)
Other current liabilities	(61)	(38)	20
Pension and other employee benefit obligations	(179)	(133)	(91)
Other, net	(71)	(73)	(58)
Net cash provided by operating activities	3,122	3,126	3,052
Investing activities			
Utility capital/construction expenditures	(3,957)	(3,244)	(3,195)
Purchases of investment securities	(853)	(1,697)	(547)
Proceeds from the sale of investment securities	833	1,669	479
Other, net	(9)	(24)	2
Net cash used in investing activities	(3,986)	(3,296)	(3,261)
Financing activities			
Proceeds from (repayments of) short-term borrowings, net	225	422	(454)
Proceeds from issuance of long-term debt	1,675	1,518	2,424
Repayments of long-term debt, including reacquisition premiums	(452)	(1,030)	(1,036)
Proceeds from issuance of common stock	230	—	—
Repurchases of common stock	(1)	(3)	(32)
Dividends paid	(730)	(721)	(681)
Other, net	(19)	(18)	(12)
Net cash provided by financing activities	928	168	209
Net change in cash and cash equivalents	64	(2)	—
Cash and cash equivalents at beginning of period	83	85	85
Cash and cash equivalents at end of period	$ 147	$ 83	$ 85
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	$ (633)	$ (616)	$ (592)
Cash received for income taxes, net	27	44	62
Supplemental disclosure of non-cash investing and financing transactions:			
Accrued property, plant and equipment additions	$ 388	$ 464	$ 311
Inventory transfers to property, plant and equipment	129	63	107
Allowance for equity funds used during construction	108	75	61
Issuance of common stock for reinvested dividends and equity awards	67	31	29

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(amounts in millions, except share and per share)

	Dec. 31 2018	Dec. 31 2017
Assets		
Current assets		
Cash and cash equivalents	$ 147	$ 83
Accounts receivable, net	860	797
Accrued unbilled revenues	755	764
Inventories	548	610
Regulatory assets	464	424
Derivative instruments	87	44
Prepaid taxes	79	68
Prepayments and other	154	183
Total current assets	3,094	2,973
Property, plant and equipment, net	36,944	34,329
Other assets		
Nuclear decommissioning fund and other investments	2,317	2,397
Regulatory assets	3,326	3,005
Derivative instruments	34	48
Deposits and other	272	278
Total other assets	5,949	5,728
Total assets	$ 45,987	$ 43,030
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$ 406	$ 457
Short-term debt	1,038	814
Accounts payable	1,237	1,243
Regulatory liabilities	436	239
Taxes accrued	450	448
Accrued interest	174	174
Dividends payable	195	183
Derivative instruments	61	29
Other	463	501
Total current liabilities	4,460	4,088
Deferred credits and other liabilities		
Deferred income taxes	4,165	3,845
Deferred investment tax credits	54	58
Regulatory liabilities	5,187	5,083
Asset retirement obligations	2,568	2,475
Derivative instruments	129	126
Customer advances	199	193
Pension and employee benefit obligations	994	1,042
Other	206	145
Total deferred credits and other liabilities	13,502	12,967
Commitments and contingencies		
Capitalization		
Long-term debt	15,803	14,520
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 514,036,787 and 507,762,881 shares outstanding at Dec. 31, 2018 and 2017, respectively	1,285	1,269
Additional paid in capital	6,168	5,898
Retained earnings	4,893	4,413
Accumulated other comprehensive loss	(124)	(125)
Total common stockholders' equity	12,222	11,455
Total liabilities and equity	$ 45,987	$ 43,030

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

(amounts in millions, shares in thousands)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
Balance at Dec. 31, 2015	507,536	$ 1,269	$ 5,889	$ 3,553	$ (110)	$ 10,601
Net income				1,123		1,123
Dividends declared on common stock ($1.36 per share)				(694)		(694)
Issuances of common stock	486	1	15			16
Repurchases of common stock	(799)	(2)	(30)			(32)
Share-based compensation			7			7
Balance at Dec. 31, 2016	507,223	$ 1,268	$ 5,881	$ 3,982	$ (110)	$ 11,021
Net income				1,148		1,148
Other comprehensive income					7	7
Dividends declared on common stock ($1.44 per share)				(736)		(736)
Issuances of common stock	611	1	4			5
Repurchases of common stock	(71)	—	(3)			(3)
Share-based compensation			16	(3)		13
Adoption of ASU No. 2018-02				22	(22)	—
Balance at Dec. 31, 2017	507,763	$ 1,269	$ 5,898	$ 4,413	$ (125)	$ 11,455
Net income				1,261		1,261
Other comprehensive income					1	1
Dividends declared on common stock ($1.52 per share)				(780)		(780)
Issuances of common stock	6,296	16	254			270
Repurchases of common stock	(22)	—	(1)			(1)
Share-based compensation			17	(1)		16
Balance at Dec. 31, 2018	514,037	$ 1,285	$ 6,168	$ 4,893	$ (124)	$ 12,222

See Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

General — Xcel Energy Inc.'s utility subsidiaries are engaged in the regulated generation, purchase, transmission, distribution and sale of electricity and in the regulated purchase, transportation, distribution and sale of natural gas.

Xcel Energy's regulated operations include the activities of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS. These utility subsidiaries serve electric and natural gas customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Also included in regulated operations are WGI, an interstate natural gas pipeline company, and WYCO, a joint venture with CIG to develop and lease natural gas pipeline, storage and compression facilities.

Xcel Energy Inc.'s nonregulated subsidiaries include Eloigne and Capital Services. Eloigne invests in rental housing projects that qualify for low-income housing tax credits. Capital Services procures equipment for construction of renewable generation facilities at other subsidiaries. Xcel Energy Inc. owns the following additional direct subsidiaries, some of which are intermediate holding companies with additional subsidiaries: Xcel Energy Wholesale Group Inc., Xcel Energy Markets Holdings Inc., Xcel Energy Ventures Inc., Xcel Energy Retail Holdings Inc., Xcel Energy Communications Group, Inc., Xcel Energy International Inc., Xcel Energy Transmission Holding Company, LLC, Nicollet Holdings Company, LLC, Nicollet Project Holdings LLC and Xcel Energy Services Inc. Xcel Energy Inc. and its subsidiaries collectively are referred to as Xcel Energy.

Xcel Energy's consolidated financial statements include its wholly-owned subsidiaries and VIEs for which it is the primary beneficiary. All intercompany transactions and balances are eliminated, unless a different treatment is appropriate for rate regulated transactions.

Xcel Energy uses the equity method of accounting for its investment in WYCO. Xcel Energy's equity earnings in WYCO are included on the consolidated statements of income as equity earnings of unconsolidated subsidiaries.

Xcel Energy has investments in certain plants and transmission facilities jointly owned with nonaffiliated utilities. Xcel Energy's proportionate share of jointly owned facilities is recorded as property, plant and equipment on the consolidated balance sheets, and Xcel Energy's proportionate share of the operating costs associated with these facilities is included in its consolidated statements of income. See Note 3 for further information.

Xcel Energy's consolidated financial statements are presented in accordance with GAAP. All of the utility subsidiaries' underlying accounting records also conform to the FERC uniform system of accounts.

Xcel Energy has evaluated events occurring after Dec. 31, 2018 up to the date of issuance of these consolidated financial statements. Statements contain all necessary adjustments and disclosures resulting from that evaluation.

Use of Estimates — Xcel Energy uses estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used on items such as plant depreciable lives or potential disallowances, AROs, certain regulatory assets and liabilities, tax provisions, uncollectible amounts, environmental costs, unbilled revenues, jurisdictional fuel and energy cost allocations and actuarially determined benefit costs. Recorded estimates are revised when better information becomes available or actual amounts can be determined. Revisions can affect operating results.

Regulatory Accounting — Xcel Energy Inc.'s regulated utility subsidiaries account for income and expense items in accordance with accounting guidance for regulated operations. Under this guidance:

- Certain costs, which would otherwise be charged to expense or other comprehensive income, are deferred as regulatory assets based on the expected ability to recover the costs in future rates.
- Certain credits, which would otherwise be reflected as income or other comprehensive income, are deferred as regulatory liabilities based on the expectation the amounts will be returned to customers in future rates, or because the amounts were collected in rates prior to the costs being incurred.

Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with the treatment in the rate setting process.

If changes in the regulatory environment occur, the utility subsidiaries may no longer be eligible to apply this accounting treatment, and may be required to eliminate regulatory assets and liabilities from their balance sheets. Such changes could have a material effect on Xcel Energy's results of operations, financial condition or cash flows.

See Note 4 for further information.

Income Taxes — Xcel Energy accounts for income taxes using the asset and liability method, which requires deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Xcel Energy defers income taxes for all temporary differences between pretax financial and taxable income, and between the book and tax bases of assets and liabilities. Xcel Energy uses the tax rates that are scheduled to be in effect when the temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the period that includes the enactment date.

The effects of tax rate changes that are attributable to the utility subsidiaries are generally subject to a normalization method of accounting. Therefore, the revaluation of most of the utility subsidiaries' net deferred taxes upon a tax rate reduction results in the establishment of a net regulatory liability which will be refundable to utility customers over the remaining life of the related assets. A tax rate increase would result in the establishment of a similar regulatory asset.

Reversal of certain temporary differences are accounted for as current income tax expense due to the effects of past regulatory practices when deferred taxes were not required to be recorded due to the use of flow through accounting for ratemaking purposes. Tax credits are recorded when earned unless there is a requirement to defer the benefit and amortize it over the book depreciable lives of the related property. The requirement to defer and amortize tax credits only applies to federal ITCs related to public utility property. Utility rate regulation also has resulted in the recognition of regulatory assets and liabilities related to income taxes.

Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized.

Xcel Energy follows the applicable accounting guidance to measure and disclose uncertain tax positions that it has taken or expects to take in its income tax returns. Xcel Energy recognizes a tax position in its consolidated financial statements when it is more likely than not that the position will be sustained upon examination based on the technical merits of the position.

Recognition of changes in uncertain tax positions are reflected as a component of income tax.

Xcel Energy reports interest and penalties related to income taxes within the other income and interest charges in the consolidated statements of income.

Xcel Energy Inc. and its subsidiaries file consolidated federal income tax returns as well as consolidated or separate state income tax returns. Federal income taxes paid by Xcel Energy Inc. are allocated to its subsidiaries based on separate company computations. A similar allocation is made for state income taxes paid by Xcel Energy Inc. in connection with consolidated state filings. Xcel Energy Inc. also allocates its own income tax benefits to its direct subsidiaries.

See Note 7 for further information.

Property, Plant and Equipment and Depreciation — Property, plant and equipment is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and AFUDC. The cost of plant retired is charged to accumulated depreciation and amortization. Amounts recovered in rates for future removal costs are recorded as regulatory liabilities. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance costs are charged to expense as incurred. Maintenance and replacement of items determined to be less than a unit of property are charged to operating expenses as incurred. Planned maintenance activities are charged to operating expense unless the cost represents the acquisition of an additional unit of property or the replacement of an existing unit of property.

Property, plant and equipment is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. A loss is recognized in the current period if it becomes probable that part of a cost of a plant under construction or recently completed plant will be disallowed for recovery from customers and a reasonable estimate of the disallowance can be made. For investments in property, plant and equipment that are abandoned and not expected to go into service, incurred costs and related deferred tax amounts are compared to the discounted estimated future rate recovery, and a loss is recognized, if necessary.

Xcel Energy records depreciation expense using the straight-line method over the plant's useful life. Actuarial life studies are performed and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 3.1% for 2018, 3.1% for 2017 and 2.9% for 2016.

See Note 3 for further information.

AROs — Xcel Energy Inc.'s utility subsidiaries account for AROs under accounting guidance that requires a liability for the fair value of an ARO to be recognized in the period in which it is incurred if it can be reasonably estimated, with the offsetting associated asset retirement costs capitalized as a long-lived asset. The liability is generally increased over time by applying the effective interest method of accretion, and the capitalized costs are depreciated over the useful life of the long-lived asset. Changes resulting from revisions to the timing or amount of expected asset retirement cash flows are recognized as an increase or a decrease in the ARO. Xcel Energy Inc.'s utility subsidiaries also recover through rates certain future plant removal costs in addition to AROs. The accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

See Note 12 for further information.

Nuclear Decommissioning — Nuclear decommissioning studies that estimate NSP-Minnesota's ultimate costs of decommissioning its nuclear power plants are performed at least every three years and submitted to the state commissions for approval.

For ratemaking purposes, NSP-Minnesota recovers the decommissioning costs of its nuclear power plants over each facility's expected service life based on the triennial decommissioning studies. The studies consider estimated future costs of decommissioning and the market value of investments in trust funds, and recommend annual funding amounts. Amounts collected in rates are deposited in the trust funds. For financial reporting purposes, NSP-Minnesota accounts for nuclear decommissioning as an ARO.

Restricted funds for the payment of future decommissioning expenditures for NSP-Minnesota's nuclear facilities are included in nuclear decommissioning fund and other assets on the consolidated balance sheets.

See Note 10 for further information.

Benefit Plans and Other Postretirement Benefits — Xcel Energy maintains pension and postretirement benefit plans for eligible employees. Recognizing the cost of providing benefits and measuring the projected benefit obligation of these plans requires management to make various assumptions and estimates.

Certain unrecognized actuarial gains and losses and unrecognized prior service costs or credits are deferred as regulatory assets and liabilities, rather than recorded as other comprehensive income, based on regulatory recovery mechanisms.

See Note 11 for further information.

Environmental Costs — Environmental costs are recorded when it is probable Xcel Energy is liable for remediation costs and the liability can be reasonably estimated. Costs are deferred as a regulatory asset if it is probable that the costs will be recovered from customers in future rates. Otherwise, the costs are expensed. If an environmental expense is related to facilities currently in use, such as emission-control equipment, the cost is capitalized and depreciated over the life of the plant.

Estimated remediation costs are regularly adjusted as estimates are revised and remediation proceeds. If other participating PRPs exist and acknowledge their potential involvement with a site, costs are estimated and recorded only for Xcel Energy's expected share of the cost.

Future costs of restoring sites are treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for removal expenses. Removal costs recovered in rates before the related costs are incurred are classified as a regulatory liability.

See Note 12 for further information.

Revenue From Contracts With Customers — Performance obligations related to the sale of energy are satisfied as energy is delivered to customers. Xcel Energy recognizes revenue that corresponds to the price of the energy delivered to the customer. The measurement of energy sales to customers is generally based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recognized.

Xcel Energy does not recognize a separate financing component of its collections from customers as contract terms are short-term in nature. Xcel Energy presents its revenues net of any excise or sales taxes or fees.

Xcel Energy's utility subsidiaries recognize sales to customers on a gross basis in electric revenues and cost of sales. Revenues and charges for short term wholesale sales of excess energy transacted through RTOs are also recorded on a gross basis. Other RTO revenues and charges are recorded on a net basis in cost of sales.

See Note 6 for further information.

Cash and Cash Equivalents — Xcel Energy considers investments in instruments with a remaining maturity of three months or less at the time of purchase, to be cash equivalents.

Accounts Receivable and Allowance for Bad Debts — Accounts receivable are stated at the actual billed amount net of an allowance for bad debts. Xcel Energy establishes an allowance for uncollectible receivables based on a policy that reflects its expected exposure to the credit risk of customers. As of Dec. 31, 2018 and 2017, the allowance for bad debts was $55 million and $52 million, respectively.

Inventory — Inventory is recorded at average cost and consisted of the following:

(Millions of Dollars)	Dec. 31, 2018	Dec. 31, 2017
Inventories		
Materials and supplies	$ 271	$ 311
Fuel	170	186
Natural gas	107	113
	$ 548	$ 610

Fair Value Measurements — Xcel Energy presents cash equivalents, interest rate derivatives, commodity derivatives and nuclear decommissioning fund assets at estimated fair values in its consolidated financial statements. Cash equivalents are recorded at cost plus accrued interest; money market funds are measured using quoted NAVs. For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used to establish fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price, Xcel Energy may use quoted prices for similar contracts or internally prepared valuation models to determine fair value.

For the pension and postretirement plan assets and nuclear decommissioning fund, published trading data and pricing models, generally using the most observable inputs available, are utilized to estimate fair value for each security.

See Notes 10 and 11 for further information.

Derivative Instruments — Xcel Energy uses derivative instruments in connection with its interest rate, utility commodity price, vehicle fuel price and commodity trading activities, including forward contracts, futures, swaps and options. Any derivative instruments not qualifying for the normal purchases and normal sales exception are recorded on the consolidated balance sheets at fair value as derivative instruments. Classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship. Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. Classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms.

Gains or losses on commodity trading transactions are recorded as a component of electric operating revenues; hedging transactions for vehicle fuel costs are recorded as a component of capital projects and O&M costs; and interest rate hedging transactions are recorded as a component of interest expense.

Normal Purchases and Normal Sales — Xcel Energy enters into contracts for purchases and sales of commodities for use in its operations. At inception, contracts are evaluated to determine whether a derivative exists and/or whether an instrument may be exempted from derivative accounting if designated as a normal purchase or normal sale.

See Note 10 for further information.

Commodity Trading Operations — All applicable gains and losses related to commodity trading activities are shown on a net basis in electric operating revenues in the consolidated statements of income.

Commodity trading activities are not associated with energy produced from Xcel Energy's generation assets or energy and capacity purchased to serve native load. Commodity trading contracts are recorded at fair market value and commodity trading results include the impact of all margin-sharing mechanisms.

See Note 10 for further information.

Other Utility Items

AFUDC — AFUDC represents the cost of capital used to finance utility construction activity. AFUDC is computed by applying a composite financing rate to qualified CWIP. The amount of AFUDC capitalized as a utility construction cost is credited to other nonoperating income (for equity capital) and interest charges (for debt capital). AFUDC amounts capitalized are included in Xcel Energy's rate base for establishing utility rates.

Alternative Revenue — Certain rate rider mechanisms (including decoupling and CIP/DSM programs) qualify as alternative revenue programs under GAAP. These mechanisms arise from costs imposed upon the utility by action of a regulator or legislative body related to an environmental, public safety or other mandate. When certain criteria are met, such as collection within 24 months, revenue is recognized equal to the revenue requirement, which may include incentives and return on rate base items. Billing amounts are revised periodically for differences between total amount collected and revenue earned, which may increase or decrease the level of revenue collected from customers. Alternative revenues arising from these programs are presented on a gross basis and disclosed separately from revenue from contracts with customers.

See Note 6 for further information.

Conservation Programs — Costs incurred for DSM and CIP programs are deferred if it is probable future revenue will recover the incurred cost. Revenues recognized for incentive programs for the recovery of lost margins and/or conservation performance incentives are limited to amounts expected to be collected within 24 months from when they are earned. Regulatory assets are recognized to reflect the amount of costs or earned incentives that have not yet been collected from customers.

Emission Allowances — Emission allowances are recorded at cost plus broker commission fees. The inventory accounting model is utilized for all emission allowances and sales of these allowances are included in electric revenues.

Nuclear Refueling Outage Costs — Xcel Energy uses a deferral and amortization method for nuclear refueling costs. This method amortizes refueling outage costs over the period between refueling outages consistent with rate recovery.

RECs — Cost of RECs that are utilized for compliance is recorded as electric fuel and purchased power expense. In certain jurisdictions, Xcel Energy reduces recoverable fuel costs for the cost of RECs and records that cost as a regulatory asset when the amount is recoverable in future rates.

Sales of RECs are recorded in electric revenues on a gross basis. The cost of these RECs and amounts credited to customers under margin-sharing mechanisms are recorded in electric fuel and purchased power expense.

2. Accounting Pronouncements

Recently Issued

Leases — In 2016, the FASB issued *Leases, Topic 842 (ASU No. 2016-02)*, which requires balance sheet recognition of right-of-use assets and lease liabilities for most leases. Adoption will occur on Jan. 1, 2019 utilizing the package of transition practical expedients provided by the new standard, including carrying forward prior conclusions of whether agreements existing before the adoption date contain leases, and whether existing leases are operating or capital/finance leases. Xcel Energy expects to utilize other expedients offered by the new standard and *Leases, Topic 842 (ASU No. 2018-11)*, including elections to not recognize short term leases on the consolidated balance sheet for certain classes of assets and to implement the standard on a prospective basis. Xcel Energy's implementation of the new guidance is substantially complete, and is expected to result in the recognition of approximately $2 billion of right-of-use assets and lease liabilities in the first quarter of 2019 for operating leases for the use of real estate, equipment and certain natural gas generating facilities operated under PPAs. The implementation is not expected to have a significant impact on Xcel Energy's consolidated financial statements, other than first-time recognition of these operating leases on the consolidated balance sheet.

Recently Adopted

Revenue Recognition — In 2014, the FASB issued *Revenue from Contracts with Customers, Topic 606 (ASU No. 2014-09)*, which provides a new framework for the recognition of revenue. Xcel Energy implemented the guidance on a modified retrospective basis on Jan. 1, 2018. Results for reporting periods beginning after Dec. 31, 2017 are presented in accordance with Topic 606, while prior period results have not been adjusted and continue to be reported in accordance with prior accounting guidance. The implementation did not have a material impact on Xcel Energy's consolidated financial statements, other than increased disclosures regarding revenues related to contracts with customers.

Classification and Measurement of Financial Instruments — In 2016, the FASB issued *Recognition and Measurement of Financial Assets and Financial Liabilities, Subtopic 825-10 (ASU No. 2016-01)*, which eliminated the available-for-sale classification for marketable equity securities and also replaced the cost method of accounting for non-marketable equity securities with a model for recognizing impairments and observable price changes. Xcel Energy implemented the guidance on Jan. 1, 2018 and the adoption impacts were not material.

Presentation of Net Periodic Benefit Cost — In 2017, the FASB issued *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, Topic 715 (ASU No. 2017-07)*, which establishes that only the service cost portion of pension cost may be presented as a component of operating income. In addition, only the service cost portion of pension cost is eligible for capitalization. As a result of regulatory accounting treatment, a similar amount of pension cost, including non-service components, will be recognized consistent with historical ratemaking and the impacts of adoption are limited to changes in classification of non-service costs in the consolidated statements of income.

Xcel Energy implemented the new guidance on Jan. 1, 2018. As a result, $33 million and $26 million of pension costs were retrospectively reclassified from operating and maintenance expenses to other expense, net on the consolidated statements of income for 2017 and 2016, respectively. Xcel Energy used benefit cost amounts disclosed for prior periods as the basis for retrospective application.

3. Property, Plant and Equipment

Major classes of property, plant and equipment:

(Millions of Dollars)	Dec. 31, 2018	Dec. 31, 2017
Property, plant and equipment		
Electric plant	$ 41,472	$ 39,016
Natural gas plant	6,210	5,800
Common and other property	2,154	2,013
Plant to be retired [(a)]	322	11
CWIP	2,091	2,087
Total property, plant and equipment	52,249	48,927
Less accumulated depreciation	(15,659)	(15,000)
Nuclear fuel	2,771	2,697
Less accumulated amortization	(2,417)	(2,295)
	$ 36,944	$ 34,329

(a) In 2018, the CPUC approved early retirement of PSCo's Comanche Units 1 and 2 in approximately 2022 and 2025, respectively. PSCo also expects Craig Unit 1 to be retired early in 2025. Amounts are presented net of accumulated depreciation.

Joint Ownership of Generation, Transmission and Gas Facilities

The utility subsidiaries' jointly owned assets as of Dec. 31, 2018:

(Millions of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Percent Owned
NSP-Minnesota				
Electric Generation:				
Sherco Unit 3	$ 604	$ 415	$ 1	59%
Sherco Common Facilities	145	100	1	80
Other	5	4	—	59
Electric Transmission:				
CapX2020 Transmission	960	73	2	51
Other	11	2	—	50
Total NSP-Minnesota	$ 1,725	$ 594	$ 4	

(Millions of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Percent Owned
NSP-Wisconsin				
Electric Transmission:				
La Crosse, WI to Madison, WI	$ 175	$ 2	$ —	37%
CapX2020 Transmission	169	15	2	81
Total NSP-Wisconsin	$ 344	$ 17	$ 2	

(Millions of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Percent Owned
PSCo				
Electric Generation:				
Hayden Unit 1	$ 153	$ 76	$ —	76%
Hayden Unit 2	149	68	—	37
Hayden Common Facilities	41	21	—	53
Craig Units 1 and 2	81	40	—	10
Craig Common Facilities	39	21	—	7
Comanche Unit 3	886	130	—	67
Comanche Common Facilities	28	3	—	82
Electric Transmission:				
Transmission and other facilities	183	63	1	Various
Gas Transportation:				
Rifle, CO to Avon, CO	22	7	—	60
Gas Transportation Compressor	8	1	—	50
Total PSCo	$ 1,590	$ 430	$ 1	

Each company's share of operating expenses and construction expenditures are included in the applicable utility accounts. Respective owners are responsible for providing their own financing.

4. Regulatory Assets and Liabilities

Regulatory assets and liabilities are created for amounts that regulators may allow to be collected, or may require to be paid back to customers in future electric and natural gas rates. Xcel Energy would be required to recognize the write-off of regulatory assets and liabilities in net income or other comprehensive income if changes in the utility industry no longer allow for the application of regulatory accounting guidance under GAAP.

Components of regulatory assets:

(Millions of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2018		Dec. 31, 2017	
Regulatory Assets			Current	Non- current	Current	Non- current
Pension and retiree medical obligations	11	Various	$ 87	$ 1,500	$ 91	$ 1,499
Net AROs [(a)]	1, 12	Plant lives	—	452	—	301
Excess deferred taxes - TCJA	7	Various	—	296	—	254
Recoverable deferred taxes on AFUDC recorded in plant		Plant lives	—	264	—	244
Environmental remediation costs	1, 12	Various	17	155	16	165
Depreciation differences		One to thirteen years	18	107	20	69
Benson biomass PPA termination and asset purchase		Ten years	10	86	—	—
Contract valuation adjustments [(b)]	1, 10	Term of related contract	17	77	21	93
Laurentian biomass PPA termination		Five years	18	73	—	—
Purchased power contract costs		Term of related contract	4	63	3	67
PI EPU		Sixteen years	3	56	3	58
Losses on reacquired debt		Term of related debt	4	44	5	48
State commission adjustments		Plant lives	1	29	1	29
Conservation programs [(c)]	1	One to two years	42	28	50	32
Property tax		Various	14	10	8	24
Nuclear refueling outage costs	1	One to two years	37	14	49	20
Deferred purchased natural gas and electric energy costs		One to three years	57	13	21	13
Renewable resources and environmental initiatives		One to two years	39	9	48	10
Sales true up and revenue decoupling		One to two years	38	7	37	12
Gas pipeline inspection and remediation costs		One to two years	28	3	24	12
Other		Various	30	40	27	55
Total regulatory assets			$ 464	$ 3,326	$ 424	$ 3,005

(a) Includes amounts recorded for future recovery of AROs, less amounts recovered through nuclear decommissioning accruals and gains from decommissioning investments.

(b) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.

(c) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.

Components of regulatory liabilities:

(Millions of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2018		Dec. 31, 2017	
Regulatory Liabilities			Current	Non- current	Current	Non- current
Deferred income tax adjustments and TCJA refunds [(a)]	7	Various	$ 157	$ 3,715	$ —	$ 3,790
Plant removal costs	1, 12	Plant lives	—	1,175	—	1,131
Effects of regulation on employee benefit costs [(b)]		Various	—	137	—	46
Renewable resources and environmental initiatives		Various	9	54	19	60
ITC deferrals [(c)]	1	Various	—	40	—	23
Deferred electric, natural gas and steam production costs		Less than one year	102	—	104	—
Contract valuation adjustments [(d)]	1, 10	Less than one year	26	—	30	—
Conservation programs [(e)]	1	Less than one year	36	—	23	—
DOE settlement		Less than one year	19	—	18	—
Other		Various	87	66	45	33
Total regulatory liabilities [(f)]			$ 436	$ 5,187	$ 239	$ 5,083

(a) Includes the revaluation of recoverable/regulated plant ADIT and revaluation impact of non-plant ADIT due to the TCJA.

(b) Includes regulatory amortization and certain TCJA benefits approved by the CPUC to offset the PSCo prepaid pension asset at Dec. 31, 2018.

(c) Includes impact of lower federal tax rate due to the TCJA.

(d) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.

(e) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.

(f) Revenue subject to refund of $29 million and $15 million for 2018 and 2017, respectively, is included in other current liabilities.

At Dec. 31, 2018 and 2017, Xcel Energy's regulatory assets not earning a return primarily included the unfunded portion of pension and retiree medical obligations, net AROs and Laurentian biomass PPA termination costs/obligations. In addition, regulatory assets included $178 million and $212 million at Dec. 31, 2018 and 2017, respectively, of past expenditures not earning a return. Amounts largely related to purchased natural gas and electric energy costs, various renewable resources and certain environmental initiatives.

5. Borrowings and Other Financing Instruments

Short-Term Borrowings

Short-Term Debt — Xcel Energy Inc. and its utility subsidiaries meet their short-term liquidity requirements primarily through the issuance of commercial paper, term loan borrowings and letters of credit under their credit facilities.

Short-term debt borrowings outstanding for Xcel Energy were as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2018	Year Ended Dec. 31 2018	2017	2016
Borrowing limit	$ 3,250	$ 3,250	$ 3,250	$ 2,750
Amount outstanding at period end	1,038	1,038	814	392
Average amount outstanding	500	788	644	485
Maximum amount outstanding	1,038	1,349	1,247	1,183
Weighted average interest rate, computed on a daily basis	2.76%	2.34%	1.35%	0.74%
Weighted average interest rate at end of period	2.97	2.97	1.90	0.95

Term Loan Agreement — In December 2018, Xcel Energy Inc. renewed its $500 million 364-Day Term Loan Agreement with $250 million outstanding. In February 2019, Xcel Energy borrowed the remaining amount. No additional capacity remains as loans borrowed and repaid may not be redrawn. The loan is unsecured and matures Dec. 3, 2019. Xcel Energy has an option to request an extension through Dec. 2, 2020. Term loan includes one financial covenant, requiring Xcel Energy's consolidated funded debt to total capitalization ratio to be less than or equal to 65 percent. Interest is at a rate equal to either (i) the Eurodollar rate, plus 50.0 basis points, or (ii) an alternate base rate. Xcel Energy is also required to pay a commitment fee equal to 10 basis points per annum on the unborrowed portion.

Letters of Credit — Xcel Energy Inc. and its subsidiaries use letters of credit, typically with terms of one year, to provide financial guarantees for certain operating obligations. As of Dec. 31, 2018 and 2017, there were $49 million and $30 million of letters of credit outstanding. Amounts approximate their fair value.

Credit Facilities — Xcel Energy Inc. and its utility subsidiaries must have revolving credit facilities in place at least equal to the amount of their commercial paper borrowing limits and cannot issue commercial paper exceeding available capacity under these credit facilities. The lines of credit provide short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

Features of the credit facilities:

	Debt-to-Total Capitalization Ratio [(a)] 2018	2017	Amount Facility May Be Increased (millions)	Additional Periods For Which a One-Year Extension May Be Requested [(b)]
Xcel Energy Inc. [(c)]	58%	58%	$ 200	2
NSP-Wisconsin	48	47	N/A	1
NSP-Minnesota	48	48	100	2
SPS	46	46	50	2
PSCo	46	44	100	2

(a) Each credit facility has a financial covenant requiring that the debt-to-total capitalization ratio be less than or equal to 65%.

(b) All extension requests are subject to majority bank group approval.

(c) The Xcel Energy Inc. credit facility has a cross-default provision that Xcel Energy Inc. will be in default on its borrowings under the facility if it or any of its subsidiaries (except NSP-Wisconsin as long as its total assets do not comprise more than 15% of Xcel Energy's consolidated total assets) default on indebtedness in an aggregate principal amount exceeding $75 million.

If Xcel Energy Inc. or its utility subsidiaries do not comply with the covenant, an event of default may be declared, and if not remedied, any outstanding amounts due under the facility can be declared due by the lender. As of Dec. 31, 2018, Xcel Energy Inc. and its subsidiaries were in compliance with all financial covenants.

Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available as of Dec. 31, 2018:

(Millions of Dollars)	Credit Facility [(a)]	Drawn [(b)]	Available
Xcel Energy Inc.	$ 1,500	$ 488	$ 1,012
PSCo	700	317	383
NSP-Minnesota	500	187	313
SPS	400	44	356
NSP-Wisconsin	150	51	99
Total	$ 3,250	$ 1,087	$ 2,163

(a) These credit facilities mature in June 2021, with the exception of Xcel Energy's Inc.'s 364-day term loan agreement which expires in December 2019.

(b) Includes outstanding commercial paper, term loan borrowings and letters of credit.

All credit facility bank borrowings, outstanding letters of credit, term loan borrowings and outstanding commercial paper reduce the available capacity under the credit facilities. Xcel Energy Inc. and its subsidiaries had no direct advances on facilities outstanding as of Dec. 31, 2018 and 2017.

Long-Term Borrowings and Other Financing Instruments

Generally, all property of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS are subject to the liens of their first mortgage indentures. Debt premiums, discounts and expenses are amortized over the life of the related debt. The premiums, discounts and expenses for refinanced debt are deferred and amortized over the life of the new issuance.

Long term debt obligations for Xcel Energy Inc. and its utility subsidiaries as of Dec. 31:

(Millions of Dollars)	Maturity Range	Interest Rate Range 2018	Interest Rate Range 2017	2018	2017
Xcel Energy Inc.					
Unsecured senior notes	2020 - 2041	2.40% - 6.50%	1.20% - 6.50%	$ 3,400	$ 2,900
Elimination of PSCo capital lease obligation with affiliates				(60)	(62)
Unamortized discount				(5)	(2)
Unamortized debt issuance cost				(21)	(20)
Current maturities (Capital lease obligation)				2	2
Total				$ 3,316	$ 2,818

(Millions of Dollars)	Maturity Range	Interest Rate Range 2018	Interest Rate Range 2017	2018	2017
NSP-Minnesota					
Mortgage bonds	2020 - 2047	2.15% - 7.13%	2.15% - 7.13%	$ 5,000	$ 5,000
Unamortized discount				(21)	(22)
Unamortized debt issuance cost				(42)	(45)
Current maturities				—	—
Total				$ 4,937	$ 4,933

(Millions of Dollars)	Maturity Range	Interest Rate Range 2018	Interest Rate Range 2017	2018	2017
NSP-Wisconsin					
Mortgage bonds	2024 - 2048	3.3% - 6.38%	3.3% - 6.38%	$ 800	$ 750
City of La Crosse resource recovery bond	2021	6.00%	6.00%	19	19
Other				—	2
Unamortized discount				(3)	(3)
Unamortized debt issuance cost				(9)	(7)
Current maturities				—	(151)
Total				$ 807	$ 610

(Millions of Dollars)	Maturity Range	Interest Rate Range 2018	Interest Rate Range 2017	2018	2017
PSCo					
Capital lease obligations	2025 - 2060	11.20% - 14.30%	11.20% - 14.30%	$ 145	$ 151
Mortgage bonds	2019 - 2048	2.25% - 6.50%	2.25% - 6.50%	4,900	4,500
Unamortized discount				(14)	(13)
Unamortized debt issuance cost				(33)	(29)
Current maturities				(406)	(306)
Total				$ 4,592	$ 4,303

(Millions of Dollars)	Maturity Range	Interest Rate Range 2018	Interest Rate Range 2017	2018	2017
SPS					
Mortgage bonds	2024 - 2048	3.30% - 4.50%	3.30% - 4.50%	$ 1,800	$ 1,500
Unsecured senior notes	2033 - 2036	6.00%	6.00% - 8.75%	350	350
Unamortized discount				(4)	(2)
Unamortized debt issuance cost				(20)	(18)
Current maturities				—	—
Total				$ 2,126	$ 1,830

(Millions of Dollars)	Maturity Range	Interest Rate Range 2018	Interest Rate Range 2017	2018	2017
Other Subsidiaries					
Various Eloigne Co. affordable housing project notes	2019 - 2052	0.00% - 6.90%	0.00% - 7.05%	$ 26	$ 28
Current maturities				(1)	(2)
Total				$ 25	$ 26

Maturities of long-term debt:

(Millions of Dollars)	
2019	$ 406
2020	1,257
2021	425
2022	902
2023	653

2018 financings:

	Amount	Financing Instrument	Interest Rate	Maturity Date
Xcel Energy Inc.	$500 million	Senior Notes	4.00%	June 15, 2028
PSCo	350 million	First mortgage bonds	3.70	June 15, 2028
PSCo	350 million	First mortgage bonds	4.10	June 15, 2048
NSP-Wisconsin	200 million	First mortgage bonds	4.20	Sept. 1, 2048
SPS	300 million	First mortgage bonds	4.40	Nov 15, 2048

2017 financings:

	Amount	Financing Instrument	Interest Rate	Maturity Date
PSCo	$400 million	First mortgage bonds	3.80%	June 15, 2047
SPS	450 million	First mortgage bonds	3.70	Aug. 15, 2047
NSP-Minnesota	600 million	First mortgage bonds	3.60	Sept. 15, 2047
NSP-Wisconsin	100 million	First mortgage bonds	3.75	Dec. 1, 2047

Forward Equity Agreements — In November 2018, Xcel Energy Inc. entered into forward sale agreements in connection with a completed $459 million public offering of 9.4 million shares of Xcel Energy common stock. The initial forward agreement was for 8.1 million shares with an additional agreement of 1.2 million shares exercised at the option of the banking counterparty. At Dec. 31, 2018, the forward agreements could have been settled with physical delivery of 9.4 million common shares to the banking counterparty in exchange for cash of $456 million. The forward instruments could also have been settled at Dec. 31, 2018 with delivery of approximately $24 million of cash or approximately 0.5 million shares of common stock to the counterparty, if Xcel Energy unilaterally elected net cash or net share settlement, respectively. The forward price used to determine amounts due at settlement is calculated based on the November 2018 public offering price for Xcel Energy's common stock of $49.00, increased for the overnight bank funding rate, less a spread of 0.75% and less expected dividends on Xcel Energy's common stock during the period the instruments are outstanding.

Xcel Energy may settle the agreements at any time up to the maturity date of February 7, 2020. Depending on settlement timing, cash proceeds are expected to be approximately $450 million to $460 million.

Forward equity instruments were recognized within stockholders' equity at fair value at execution of the agreements, and will not be subsequently adjusted until settlement.

ATM Equity Offering — Xcel Energy issued 4.7 million shares of common stock with net proceeds of $224.7 million through the at-the-market program. In addition, transaction fees of $1.9 million were paid. In November 2018, the ATM offering was closed.

Other Equity — Xcel Energy issued $38.5 million and $39.2 million of equity through the DRIP program during the years ended Dec. 31, 2018 and 2017 respectively. Program allows stockholders to elect dividend reinvestment in Xcel Energy common stock through a non-cash transaction. See Note 8 for equity items related to share based compensation.

Deferred Financing Costs — Deferred financing costs of approximately $126 million and $119 million, net of amortization, are presented as a deduction from the carrying amount of long-term debt as of Dec. 31, 2018 and 2017, respectively.

Capital Stock — Preferred stock authorized/outstanding:

	Preferred Stock Authorized (Shares)	Par Value of Preferred Stock	Preferred Stock Outstanding (Shares) 2018 and 2017
Xcel Energy Inc.	7,000,000	$ 100	—
PSCo	10,000,000	0.01	—
SPS	10,000,000	1.00	—

Xcel Energy Inc. had the following common stock authorized/outstanding:

Commons Stock Authorized (Shares)	Par Value of Common Stock	Common Stock Outstanding (Shares) 2018	Common Stock Outstanding (Shares) 2017
1 billion	$ 2.50	514,036,787	507,762,881

Dividend and Other Capital-Related Restrictions — Xcel Energy depends on its subsidiaries to pay dividends. Xcel Energy Inc.'s utility subsidiaries' dividends are subject to the FERC's jurisdiction, which prohibits the payment of dividends out of capital accounts. Dividends are solely to be paid from retained earnings. Certain covenants also require Xcel Energy Inc. to be current on interest payments prior to dividend disbursements.

State regulatory commissions impose dividend limitations for NSP-Minnesota, NSP-Wisconsin and SPS.

Requirements and actuals as of Dec. 31, 2018:

	Equity to Total Capitalization Ratio Required Range		Equity to Total Capitalization Ratio Actual
	Low	High	2018
NSP-Minnesota	47.1%	57.5%	52.3%
NSP-Wisconsin	51.5	N/A	51.8
SPS [(a)]	45.0	55.0	54.4

(a) SPS excludes short-term debt.

	Unrestricted Retained Earnings	Total Capitalization	Limit on Total Capitalization
NSP-Minnesota	$ 1.0 billion	$ 10.7 billion	$ 11.5 billion
NSP-Wisconsin [(a)]	11.5 million	1.7 billion	N/A
SPS [(b)]	605.7 million	4.7 billion	N/A

(a) NSP-Wisconsin cannot pay annual dividends in excess of approximately $55 million if its average equity-to-total capitalization ratio falls below the commission authorized level.

(b) SPS may not pay a dividend that would cause it to lose its investment grade bond rating.

Issuance of securities by Xcel Energy Inc. generally is not subject to regulatory approval. However, utility financings and intra-system financings are subject to the jurisdiction of state regulatory commissions and/or the FERC. Xcel Energy may seek additional authorization as necessary.

Authorizations as of Dec. 31, 2018:

	Amount Authorized to Issue			
	Long-Term Debt		Short-Term Debt	
NSP-Minnesota	52.93% of total capitalization	(a)	$ 1.725 billion	(a)
NSP-Wisconsin	$ —	(b)	150 million	
SPS	—	(b)	600 million	
PSCo	1.1 billion		800 million	

(a) NSP-Minnesota has authorization to issue long-term securities provided the equity-to-total capitalization remains within the required range, and to issue short-term debt provided it does not exceed 15% of total capitalization.

(b) SPS and NSP-Wisconsin will file for additional long-term debt authorization.

6. Revenues

Revenue is classified by the type of goods/services rendered and market/customer type. Xcel Energy's operating revenues (subsequent to adoption of the revised revenue guidance) consists of the following:

	Year Ended Dec. 31, 2018			
(Millions of Dollars)	Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 2,919	$ 988	$ 38	$ 3,945
C&I	4,874	524	25	5,423
Other	134	—	6	140
Total retail	7,927	1,512	69	9,508
Wholesale	791	—	—	791
Transmission	523	—	—	523
Other	98	100	—	198
Total revenue from contracts with customers	9,339	1,612	69	11,020
Alternative revenue and other	380	127	10	517
Total revenues	$ 9,719	$ 1,739	$ 79	$ 11,537

7. Income Taxes

Federal Tax Reform — In 2017, the TCJA was signed into law. The key provisions impacting Xcel Energy, generally beginning in 2018, include:

- Corporate federal tax rate reduction from 35% to 21%;
- Normalization of resulting plant-related excess deferred taxes;
- Elimination of the corporate alternative minimum tax;
- Continued interest expense deductibility and discontinued bonus depreciation for regulated public utilities;
- Limitations on certain executive compensation deductions;
- Limitations on certain deductions for NOLs arising after Dec. 31, 2017 (limited to 80% of taxable income);
- Repeal of the section 199 manufacturing deduction; and
- Reduced deductions for meals and entertainment as well as state and local lobbying.

Xcel Energy estimated the effects of the TCJA, which have been reflected in the consolidated financial statements.

Reductions in deferred tax assets and liabilities due to a decrease in corporate federal tax rates typically result in a net tax benefit. However, the impacts are primarily recognized as regulatory liabilities refundable to utility customers as a result of IRS requirements and past regulatory treatment.

Estimated impacts of the new tax law in December 2017 included:

- $2.7 billion ($3.8 billion grossed-up for tax) of reclassifications of plant-related excess deferred taxes to regulatory liabilities upon valuation at the new 21% federal rate. The regulatory liabilities will be amortized consistent with IRS normalization requirements, resulting in customer refunds over an estimated weighted average period of approximately 30 years;
- $254 million and $174 million of reclassifications (grossed-up for tax) of excess deferred taxes for non-plant related deferred tax assets and liabilities, respectively, to regulatory assets and liabilities; and,
- $23 million of total estimated income tax expense related to the tax rate change on certain non-plant deferred taxes and all other 2017 income statement impacts of the federal tax reform.

Xcel Energy accounted for the state tax impacts of federal tax reform based on enacted state tax laws. Any future state tax law changes related to the TCJA will be accounted for in the periods state laws are enacted.

Federal Tax Loss Carryback Claims — In 2012 - 2015, Xcel Energy identified certain expenses related to 2009, 2010, 2011, 2013, 2014 and 2015 that qualify for an extended carryback beyond the typical two-year carryback period. As a result of a higher tax rate in prior years, Xcel Energy recognized a tax benefit of approximately $5 million in 2015, $17 million in 2014, $12 million in 2013 and $15 million in 2012.

Federal Audit — Statute of limitations applicable to Xcel Energy's consolidated federal income tax returns expire as follows:

Tax Year(s)	Expiration
2009 - 2014	October 2019
2015	September 2019
2016	September 2020
2017	September 2021

In 2012, the IRS commenced an examination of tax years 2010 and 2011, including the 2009 carryback claim. In 2017, Xcel Energy and the Office of Appeals reached an agreement and the benefit related to the agreed upon portions was recognized. In the second quarter of 2018, the Joint Committee on Taxation completed its review and took no exception to the agreement. As a result, the remaining unrecognized tax benefit was released and recorded as a payable to the IRS.

In the third quarter of 2015, the IRS commenced an examination of tax years 2012 and 2013. In the third quarter of 2017, the IRS concluded the audit of tax years 2012 and 2013 and proposed an adjustment that would impact Xcel Energy's NOL and ETR. Xcel Energy filed a protest with the IRS. As of Dec. 31, 2018, the case has been forwarded to the Office of Appeals and Xcel Energy has recognized its best estimate of income tax expense that will result from a final resolution of this issue; however, the outcome and timing of a resolution is unknown.

In the fourth quarter of 2018, the IRS began an audit of tax years 2014 - 2016, however no adjustments have been proposed.

State Audits — Xcel Energy files consolidated state tax returns based on income in its major operating jurisdictions and various other state income-based tax returns.

As of Dec. 31, 2018, Xcel Energy's earliest open tax years (subject to examination by state taxing authorities in its major operating jurisdictions) were as follows:

State	Year
Colorado	2009
Minnesota	2009
Texas	2010
Wisconsin	2014

- In the fourth quarter of 2018, the Minnesota audit of tax years 2010 - 2014 concluded with no material adjustments.
- In the third quarter of 2018, the Wisconsin audit of tax years 2012 - 2013 concluded with no material adjustments. In the fourth quarter of 2018, Wisconsin began an audit of tax years 2014 - 2016. No material adjustments have been proposed.
- No other state income tax audits were in progress as of Dec. 31, 2018.

Unrecognized Tax Benefits — Unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the annual ETR. In addition, the unrecognized tax benefit balance includes temporary tax positions for which the ultimate deductibility is highly certain, but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the ETR but would accelerate the payment to the taxing authority to an earlier period.

Unrecognized tax benefits - permanent vs. temporary:

(Millions of Dollars)	Dec. 31, 2018	Dec. 31, 2017
Unrecognized tax benefit — Permanent tax positions	$ 28	$ 20
Unrecognized tax benefit — Temporary tax positions	9	19
Total unrecognized tax benefit	$ 37	$ 39

Changes in unrecognized tax benefits:

(Millions of Dollars)	2018	2017	2016
Balance at Jan. 1	$ 39	$ 134	$ 121
Additions based on tax positions related to the current year	9	6	8
Reductions based on tax positions related to the current year	(4)	(4)	—
Additions for tax positions of prior years	2	15	10
Reductions for tax positions of prior years	(4)	(105)	(5)
Settlements with taxing authorities	(5)	(7)	—
Balance at Dec. 31	$ 37	$ 39	$ 134

Unrecognized tax benefits were reduced by tax benefits associated with NOL and tax credit carryforwards:

(Millions of Dollars)	Dec. 31, 2018	Dec. 31, 2017
NOL and tax credit carryforwards	$ (35)	$ (31)

Net deferred tax liability associated with the unrecognized tax benefit amounts and related NOLs and tax credits carryforwards were $24 million and $13 million at Dec. 31, 2018 and Dec 31, 2017, respectively.

As the IRS Appeals and federal and state audits progress and other state audits resume, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $28 million in the next 12 months.

Payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards.

Interest payable related to unrecognized tax benefits:

(Millions of Dollars)	2018	2017	2016
Payable for interest related to unrecognized tax benefits at Jan. 1	$ —	$ (3)	$ —
Interest income (expense) related to unrecognized tax benefits	—	3	(3)
Payable for interest related to unrecognized tax benefits at Dec. 31	$ —	$ —	$ (3)

No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2018, 2017 or 2016.

Other Income Tax Matters — NOL amounts represent the tax loss that is carried forward and tax credits represent the deferred tax asset. NOL and tax credit carryforwards as of Dec. 31 were as follows:

(Millions of Dollars)	2018	2017
Federal NOL carryforward	$ —	$ 1,072
Federal tax credit carryforwards	553	517
Valuation allowances for federal credit carryforwards	(5)	(5)
State NOL carryforwards	1,104	1,592
Valuation allowances for state NOL carryforwards	(50)	(55)
State tax credit carryforwards, net of federal detriment (a)	89	90
Valuation allowances for state credit carryforwards, net of federal benefit (b)	(69)	(68)

(a) State tax credit carryforwards are net of federal detriment of $24 million as of Dec. 31, 2018 and 2017.

(b) Valuation allowances for state tax credit carryforwards were net of federal benefit of $18 million as of Dec. 31, 2018 and 2017.

Federal carryforward periods expire between 2021 and 2038 and state carryforward periods expire between 2019 and 2037.

Total income tax expense from operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense.

Effective income tax rate for years ended Dec. 31:

	2018	2017 (a)	2016 (a)
Federal statutory rate	21.0%	35.0%	35.0%
State income tax on pretax income, net of federal tax effect	5.0	4.1	4.1
Increases (decreases) in tax from:			
Regulatory differences - ARAM (b)	(5.8)	(0.1)	(0.1)
Wind production tax credits recognized	(5.2)	(4.7)	(3.4)
Other tax credits recognized, net of federal income tax expense	(2.0)	(1.0)	(0.8)
Regulatory differences - other utility plant items	(1.0)	(0.7)	(0.5)
Regulatory differences - Deferral of ARAM (c)	0.6	—	—
Change in unrecognized tax benefits	0.4	(0.6)	0.2
Tax reform	—	1.4	—
Other, net	(0.4)	(1.3)	(0.4)
Effective income tax rate	12.6%	32.1%	34.1%

(a) Prior periods have been reclassified to conform to current year presentation.

(b) ARAM is a method to flow back excess deferred taxes to customers.

(c) ARAM has been deferred when regulatory treatment has not been established. As Xcel Energy received direction from its regulatory commissions regarding the return of excess deferred taxes to customers, the ARAM deferral was reversed. This resulted in a reduction to tax expense with a corresponding reduction to revenue.

Components of income tax expense for years ended Dec. 31:

(Millions of Dollars)	2018	2017	2016
Current federal tax (benefit) expense	$ (34)	$ 1	$ (3)
Current state tax expense (benefit)	8	(11)	(4)
Current change in unrecognized tax (benefit) expense	(6)	(83)	6
Deferred federal tax expense	122	460	477
Deferred state tax expense	85	107	112
Deferred change in unrecognized tax expense (benefit)	11	73	(2)
Deferred investment tax credits	(5)	(5)	(5)
Total income tax expense	$ 181	$ 542	$ 581

Components of deferred income tax expense as of Dec. 31:

(Millions of Dollars)	2018	2017	2016
Deferred tax expense (benefit) excluding items below	$ 320	$(2,939)	$ 631
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(102)	3,583	(45)
Tax (expense) benefit allocated to other comprehensive income, net of adoption of ASU No. 2018-02, and other	—	(4)	1
Deferred tax expense	$ 218	$ 640	$ 587

Components of net deferred tax liability as of Dec. 31:

(Millions of Dollars)	2018	2017
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 5,082	$ 4,960
Regulatory assets	599	565
Pension expense	178	199
Other	64	57
Total deferred tax liabilities	$ 5,923	$ 5,781
Deferred tax assets:		
Regulatory liabilities	$ 879	$ 886
Tax credit carryforward	642	607
NOL carryforward	51	293
NOL and tax credit valuation allowances	(79)	(77)
Other employee benefits	124	132
Deferred ITCs	16	17
Rate refund	60	10
Other	65	68
Total deferred tax assets	$ 1,758	$ 1,936
Net deferred tax liability	$ 4,165	$ 3,845

8. Share-Based Compensation

Incentive Plans Including Share-Based Compensation — Xcel Energy Inc. has three incentive plans that include share-based payment elements. Plans and authorized equity shares for awards:

- Omnibus Incentive Plan - 7.0 million shares;
- Long-Term Incentive Plan - 8.3 million shares; and,
- Executive Annual Incentive Award Plan - 1.2 million shares.

Restricted Stock — The Executive Annual Incentive Award Plan and Omnibus Incentive Plan allow certain employees to elect to receive shares of common or restricted stock. Restricted stock is treated as an equity award and vests and settles in equal annual installments over a three-year period. Restricted stock has a fair value equal to the market trading price of Xcel Energy Inc.'s stock at the grant date.

Shares of restricted stock granted at Dec. 31:

(Shares in Thousands)	2018	2017	2016
Granted shares	18	15	20
Grant date fair value	$ 44.68	$ 42.00	$ 38.82

Changes in nonvested restricted stock:

(Shares in Thousands)	Shares	Weighted Average Grant Date Fair Value
Nonvested restricted stock at Jan. 1, 2018	44	$ 39.71
Granted	18	44.68
Forfeited	—	—
Vested	(27)	37.25
Dividend equivalents	1	46.27
Nonvested restricted stock at Dec. 31, 2018	36	44.29

Other Equity Awards — Xcel Energy Inc.'s Board of Directors has granted equity awards under the Xcel Energy Inc. Long-Term Incentive Plan and the Omnibus Incentive Plan. These plans include various vesting conditions and performance goals. At the end of the restricted period, such grants will be awarded if the vesting conditions and/or performance goals are met.

Certain employees are granted equity awards with a portion subject only to service conditions, and the other portion subject to performance conditions. A total of 0.3 million time-based equity shares subject only to service conditions were granted annually in 2018, 2017 and 2016, respectively.

The performance conditions for a portion of the awards granted from 2016 to 2018 are based on relative TSR and environmental goals. Equity awards with performance conditions will be settled or forfeited after three years, with payouts ranging from zero to 200 percent depending on achievement.

Equity award units granted to employees (excluding restricted stock):

(Units in Thousands)	2018	2017	2016
Granted units	500	503	522
Weighted average grant date fair value	$ 47.60	$ 41.02	$ 36.00

Equity awards vested:

(Units in Thousands)	2018	2017	2016
Vested Units	475	467	530
Total Fair Value	$ 23,393	$ 22,459	$ 21,575

Changes in the nonvested portion of equity award units for 2018:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Nonvested Units at Jan. 1, 2018	995	$ 38.48
Granted	500	47.60
Forfeited	(126)	41.74
Vested	(475)	35.92
Dividend equivalents	45	40.74
Nonvested Units at Dec. 31, 2018	939	44.30

Stock Equivalent Units — Non-employee members of Xcel Energy Inc. Board of Directors may elect to receive their annual equity grant as stock equivalent units in lieu of common stock. Each unit's value is equal to one share of Xcel Energy Inc. common stock. The annual equity grant is vested as of the date of each member's election to the Board of Directors; there is no further service or other condition. Directors may also elect to receive their cash fees as stock equivalent units in lieu of cash. Stock equivalent units are payable as a distribution of common stock upon a director's termination of service.

Stock equivalent units granted:

(Units in Thousands)	2018	2017	2016
Granted units	36	51	49
Weighted average grant date fair value	$ 45.44	$ 46.05	$ 40.68

Changes in stock equivalent units:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Stock equivalent units at Jan. 1, 2018	753	$ 29.83
Granted	36	45.44
Units distributed	(123)	31.21
Dividend equivalents	22	46.40
Stock equivalent units at Dec. 31, 2018	688	30.93

TSR Liability Awards — Xcel Energy Inc.'s Board of Directors has granted TSR liability awards under the Long-Term Incentive Plan and Omnibus Incentive Plan. The plans allow Xcel Energy to attach various performance goals to the awards granted. The liability awards have been historically dependent on relative TSR measured over a three-year period. Xcel Energy Inc.'s TSR is compared to a 22-member utilities peer group for 2016 - 2018 awards. Potential payouts of the awards range from zero to 200%.

TSR liability awards granted:

(In Thousands)	2018	2017	2016
Awards granted	239	240	264

TSR liability awards settled:

(In Thousands)	2018	2017	2016
Awards settled	482	454	354
Settlement amount (cash, common stock and deferred amounts)	$ 21,534	$ 19,083	$ 13,724

TSR liability awards of $8 million were settled in cash in 2018.

Share-Based Compensation Expense — Vesting of employee equity awards is typically predicated on the achievement of a TSR or environmental measures target, other than for restricted stock. Additionally, approximately 0.3 million of equity award units were granted annually in 2016 - 2018, with vesting subject only to service conditions of three years. Generally these instruments are considered to be equity awards as the award settlement determination (shares or cash) is made by Xcel Energy, not the participants. In addition, these awards have not been previously settled in cash and Xcel Energy plans to continue electing share settlement. Grant date fair value of equity awards is expensed over the service period.

TSR liability awards have been historically settled partially in cash, and do not qualify as equity awards, but rather are accounted for as liabilities. As liability awards, the fair value on which ratable expense is based, as employees vest in their rights to those awards, is remeasured each period based on the current stock price and performance achievement, and final expense is based on the market value of the shares on the date the award is settled.

Compensation costs related to share-based awards:

(Millions of Dollars)	2018	2017	2016
Compensation cost for share-based awards [(a)]	$ 45	$ 57	$ 41
Tax benefit recognized in income	12	22	16

(a) Compensation costs for share-based payment are included in O&M expense.

There was approximately $38 million in 2018 and $44 million in 2017 of total unrecognized compensation cost related to nonvested share-based compensation awards. Xcel Energy expects to recognize the unrecognized amount over a weighted average period of 1.6 years.

9. Earnings Per Share

Basic EPS was computed by dividing the earnings available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted EPS was computed by dividing the earnings available to common shareholders by the diluted weighted average number of common shares outstanding during the period. Diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock (i.e., common stock equivalents) were settled. The weighted average number of potentially dilutive shares outstanding used to calculate diluted EPS is calculated using the treasury stock method.

Common Stock Equivalents — Xcel Energy Inc. has common stock equivalents related to forward equity agreements and certain equity awards in share-based compensation arrangements. Common stock equivalents include commitments to issue common stock related to time based equity compensation awards.

Stock equivalent units granted to Xcel Energy Inc.'s Board of Directors are included in common shares outstanding upon grant date as there is no further service, performance or market condition associated with these awards. Restricted stock issued to employees under the Xcel Energy Inc. Executive Annual Incentive Award Plan is included in common shares outstanding when granted.

Share-based compensation arrangements for which there is currently no dilutive impact to EPS include the following:

- Equity awards subject to a performance condition; included in common shares outstanding when all necessary conditions for settlement have been satisfied by the end of the reporting period; and,
- Liability awards subject to a performance condition; any portions settled in shares are included in common shares outstanding upon settlement.

Diluted common shares outstanding included common stock equivalents of 0.5 million, 0.6 million and 0.7 million shares for 2018, 2017 and 2016.

10. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

Accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance.

- Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices.

- Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, or priced with models using highly observable inputs.
- Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

Specific valuation methods include:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted NAV.

Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. The fair values for commingled funds are measured using NAVs. The investments in commingled funds may be redeemed for NAV with proper notice. Private equity commingled fund investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate commingled funds investments may be redeemed with proper notice, however, withdrawals may be delayed or discounted as a result of fund illiquidity.

Investments in debt securities — Fair values for debt securities are determined by a third party pricing service using recent trades and observable spreads from benchmark interest rates for similar securities.

Interest rate derivatives — Fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — Methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations, and are generally assigned a Level 2 classification. When contractual settlements relate to inactive delivery locations or extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable forecasts of forward prices and volatilities on a valuation is evaluated and may result in Level 3 classification.

Electric commodity derivatives held by NSP-Minnesota and SPS include transmission congestion instruments, generally referred to as FTRs. FTRs purchased from a RTO are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path. The value of an FTR is derived from, and designed to offset, the cost of transmission congestion. In addition to overall transmission load, congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of an FTR.

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of important inputs to the value of FTRs between auction processes, including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3.

Non-trading monthly FTR settlements are included in fuel and purchased energy cost recovery mechanisms as applicable in each jurisdiction, and therefore changes in the fair value of the yet to be settled portions of most FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of FTRs relative to the electric utility operations of NSP-Minnesota and SPS, the numerous unobservable quantitative inputs pertinent to the value of FTRs are insignificant to the consolidated financial statements of Xcel Energy.

Non-Derivative Fair Value Measurements

The NRC requires NSP-Minnesota to maintain a portfolio of investments to fund the costs of decommissioning its nuclear generating plants. Assets of the nuclear decommissioning fund are legally restricted for the purpose of decommissioning these facilities. The fund contains cash equivalents, debt securities, equity securities and other investments. NSP-Minnesota uses the MPUC approved asset allocation for the escrow and investment targets by asset class for both the escrow and qualified trust.

NSP-Minnesota recognizes the costs of funding the decommissioning over the lives of the nuclear plants, assuming rate recovery of all costs. Realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund are deferred as a component of the regulatory asset.

Unrealized gains for the nuclear decommissioning fund were $450 million and $560 million as of Dec. 31, 2018 and 2017, respectively, and unrealized losses were $45 million and $7 million as of Dec. 31, 2018 and 2017, respectively.

Non-derivative instruments with recurring fair value measurements in the nuclear decommissioning fund:

	Dec. 31, 2018					
		Fair Value				
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	NAV	Total
Nuclear decommissioning fund [(a)]						
Cash equivalents	$ 24	$ 24	$ —	$ —	$ —	$ 24
Commingled funds	758	79	—	—	819	898
Debt securities	466	—	436	—	—	436
Equity securities	401	697	—	—	—	697
Total	$ 1,649	$ 800	$ 436	$ —	$ 819	$ 2,055

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $141 million of equity investments in unconsolidated subsidiaries and $121 million of rabbi trust assets and miscellaneous investments.

	Dec. 31, 2017					
		Fair Value				
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	NAV	Total
Nuclear decommissioning fund [(a)]						
Cash equivalents	$ 29	$ 29	$ —	$ —	$ —	$ 29
Commingled funds	701	223	—	—	659	882
Debt securities	438	—	441	—	—	441
Equity securities	423	791	—	—	—	791
Total	$ 1,591	$ 1,043	$ 441	$ —	$ 659	$ 2,143

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $140 million of equity investments in unconsolidated subsidiaries and $114 million of rabbi trust assets and miscellaneous investments.

For the years ended Dec. 31, 2018 and 2017, there were no Level 3 nuclear decommissioning fund investments or transfer of amounts between levels.

Contractual maturity dates of debt securities in the nuclear decommissioning fund as of Dec. 31, 2018:

	Final Contractual Maturity				
(Millions of Dollars)	Due in 1 Year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years	Total
Debt securities	$ 10	$ 107	$ 211	$ 108	$ 436

Rabbi Trusts

Xcel Energy has established rabbi trusts to provide partial funding for future distributions of its SERP and deferred compensation plan.

Cost and fair value of assets held in rabbi trusts:

	Dec. 31, 2018				
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [a]					
Cash equivalents	$ 16	$ 16	$ —	$ —	$ 16
Mutual funds	52	51	—	—	51
Total	$ 68	$ 67	$ —	$ —	$ 67

	Dec. 31, 2017				
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [a]					
Cash equivalents	$ 12	$ 12	$ —	$ —	$ 12
Mutual funds	47	50	—	—	50
Total	$ 59	$ 62	$ —	$ —	$ 62

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet.

Derivative Fair Value Measurements

Xcel Energy enters into derivative instruments, including forward contracts, futures, swaps and options, for trading purposes and to manage risk in connection with changes in interest rates, utility commodity prices and vehicle fuel prices.

Interest Rate Derivatives — Xcel Energy enters into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes.

As of Dec. 31, 2018, accumulated other comprehensive losses related to interest rate derivatives included $3 million of net losses expected to be reclassified into earnings during the next 12 months as the hedged transactions impact earnings.

As of Dec 31, 2018, Xcel Energy had unsettled interest rate swaps outstanding with a notional amount of $300 million. These interest rate derivatives were designated as hedges, and as such, changes in fair value are recorded to other comprehensive income.

Wholesale and Commodity Trading Risk — Xcel Energy Inc.'s utility subsidiaries conduct various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy, energy-related instruments and natural gas-related instruments, including derivatives. Xcel Energy is allowed to conduct these activities within guidelines and limitations as approved by its risk management committee, comprised of management personnel not directly involved in activities governed by this policy.

Commodity Derivatives — Xcel Energy enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric and natural gas operations, as well as for trading purposes. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, natural gas for resale, FTRs, vehicle fuel and weather derivatives.

As of Dec. 31, 2018, Xcel Energy had no vehicle fuel contracts designated as cash flow hedges. Xcel Energy may enter into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers, but may not be designated as qualifying hedging transactions. Changes in the fair value of non-trading commodity derivative instruments are recorded in other comprehensive income or deferred as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Immaterial amounts to income related to the ineffectiveness of cash flow hedges were recorded for the years ended Dec. 31, 2018 and 2017.

As of Dec. 31, 2018, there were no net gains related to commodity derivative cash flow hedges recorded as a component of accumulated other comprehensive losses or related amounts expected to be reclassified into earnings during the next 12 months.

Xcel Energy enters into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving its electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in electric operating revenues, net of amounts credited to customers under margin-sharing mechanisms.

Gross notional amounts of commodity forwards, options and FTRs as of Dec. 31:

(Amounts in Millions) [a] [b]	2018	2017
MWh of electricity	87	68
MMBtu of natural gas	92	37

(a) Amounts are not reflective of net positions in the underlying commodities.

(b) Notional amounts for options are included on a gross basis, but are weighted for the probability of exercise.

Consideration of Credit Risk and Concentrations — Xcel Energy continuously monitors the creditworthiness of counterparties to its interest rate derivatives and commodity derivative contracts prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented in the consolidated balance sheets.

Xcel Energy's utility subsidiaries' most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to their wholesale, trading and non-trading commodity activities.

As of Dec. 31, 2018, six of Xcel Energy's 10 most significant counterparties for these activities, comprising $96 million or 43% of this credit exposure, had investment grade credit ratings from Standard & Poor's, Moody's or Fitch Ratings. Three of the 10 most significant counterparties, comprising $20 million or 9% of this credit exposure, were not rated by these external agencies, but based on Xcel Energy's internal analysis, had credit quality consistent with investment grade. One of these significant counterparties, comprising $12 million or 5% of this credit exposure, had credit quality less than investment grade, based on Xcel Energy's internal analysis. Eight of these significant counterparties are municipal or cooperative electric entities or other utilities.

Qualifying Cash Flow Hedges — Financial impact of qualifying interest rate and vehicle fuel cash flow hedges on Xcel Energy's accumulated other comprehensive loss, included in the consolidated statements of common stockholders' equity and in the consolidated statements of comprehensive income:

(Millions of Dollars)	2018	2017	2016
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$ (58)	$ (51)	$ (55)
After-tax net unrealized losses related to derivatives accounted for as hedges	(5)	—	—
After-tax net realized losses on derivative transactions reclassified into earnings	3	3	4
Adoption of ASU. 2018-02 (a)	—	(10)	—
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	$ (60)	$ (58)	$ (51)

(a) In 2017, Xcel Energy implemented ASU No. 2018-02 related to TCJA, which resulted in reclassification of certain credit balances within net accumulated other comprehensive loss to retained earnings.

Impact of derivative activity:

(Millions of Dollars)	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in: Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities
Year Ended Dec. 31, 2018		
Derivatives designated as cash flow hedges		
Interest rate	$ (7)	$ —
Total	$ (7)	$ —
Other derivative instruments		
Electric commodity	$ —	$ 1
Natural gas commodity	—	10
Total	$ —	$ 11
Year Ended Dec. 31, 2017		
Other derivative instruments		
Electric commodity	$ —	$ 10
Natural gas commodity	—	(13)
Total	$ —	$ (3)
Year Ended Dec. 31, 2016		
Other derivative instruments		
Electric commodity	$ —	$ 17
Natural gas commodity	—	1
Total	$ —	$ 18

(Millions of Dollars)	Pre-Tax (Gains) Losses Reclassified into Income During the Period from: Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Year Ended Dec. 31, 2018			
Derivatives designated as cash flow hedges			
Interest rate	$ 4 (a)	$ —	$ —
Total	$ 4	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ 14 (b)
Electric commodity	—	(1) (c)	—
Natural gas commodity	—	(6) (d)	(4) (d)
Total	$ —	$ (7)	$ 10
Year Ended Dec. 31, 2017			
Derivatives designated as cash flow hedges			
Interest rate	$ 5 (a)	$ —	$ —
Total	$ 5	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ 10 (b)
Electric commodity	—	(15) (c)	—
Natural gas commodity	—	3 (d)	(6) (d)
Total	$ —	$ (12)	$ 4
Year Ended Dec. 31, 2016			
Derivatives designated as cash flow hedges			
Interest rate	$ 6 (a)	$ —	$ —
Total	$ 6	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ 2 (b)
Electric commodity	—	(8) (c)	—
Natural gas commodity	—	15 (d)	(8) (d)
Total	$ —	$ 7	$ (6)

(a) Amounts recorded to interest charges.

(b) Amounts recorded to electric operating revenues. Portions of these gains and losses are subject to sharing with electric customers through margin-sharing mechanisms and deducted from gross revenue, as appropriate.

(c) Amounts recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

(d) Amounts for the year ended Dec. 31, 2018 included $1 million of settlement losses on derivatives entered to mitigate natural gas price risk for electric generation recorded to electric fuel and purchased power, subject to cost-recovery mechanisms and reclassified to a regulatory asset, as appropriate. Such gains and losses for the years ended Dec. 31, 2017 and 2016 were immaterial. Remaining settlement losses for the years ended Dec. 31, 2018, 2017 and 2016 related to natural gas operations and were recorded to cost of natural gas sold and transported. These losses are subject to cost-recovery mechanisms and reclassified out of income to a regulatory asset, as appropriate.

Xcel Energy had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2018, 2017 and 2016.

Credit Related Contingent Features — Contract provisions for derivative instruments that the utility subsidiaries enter, including those accounted for as normal purchase-normal sale contracts and therefore not reflected on the consolidated balance sheets, may require the posting of collateral or settlement of the contracts for various reasons, including if the applicable utility subsidiary's credit ratings are downgraded below its investment grade credit rating by any of the major credit rating agencies, or for cross default contractual provisions if there was a failure under other financing arrangements related to payment terms or other covenants. As of Dec. 31, 2018 and 2017, there were no derivative instruments in a liability position with such underlying contract provisions.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that a given utility subsidiary's ability to fulfill its contractual obligations is reasonably expected to be impaired. Xcel Energy had no collateral posted related to adequate assurance clauses in derivative contracts as of Dec. 31, 2018 and 2017.

Recurring Fair Value Measurements — Xcel Energy's derivative assets and liabilities measured at fair value on a recurring basis:

	Dec. 31, 2018						Dec. 31, 2017					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting [a]	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting [a]	Total
Current derivative assets												
Commodity trading	$ 4	$ 92	$ 2	$ 98	$ (44)	$ 54	$ 2	$ 22	$ —	$ 24	$ (15)	$ 9
Electric commodity	—	—	25	25	—	25	—	—	32	32	(2)	30
Natural gas commodity	—	4	—	4	—	4	—	—	—	—	—	—
Total current derivative assets	$ 4	$ 96	$ 27	$ 127	$ (44)	83	$ 2	$ 22	$ 32	$ 56	$ (17)	39
PPAs [b]						4						5
Current derivative instruments						$ 87						$ 44
Noncurrent derivative assets												
Other derivative instruments:												
Commodity trading	$ —	$ 27	$ 5	$ 32	$ (14)	$ 18	$ —	$ 31	$ 5	$ 36	$ (7)	$ 29
Total noncurrent derivative assets	$ —	$ 27	$ 5	$ 32	$ (14)	18	$ —	$ 31	$ 5	$ 36	$ (7)	29
PPAs [b]						16						19
Noncurrent derivative instruments						$ 34						$ 48

	Dec. 31, 2018						Dec. 31, 2017					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting [a]	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting [a]	Total
Current derivative liabilities												
Derivatives designated as cash flow hedges:												
Interest rate	$ —	$ 7	$ —	$ 7	$ —	$ 7	$ —	$ —	$ —	$ —	$ —	$ —
Other derivative instruments:												
Commodity trading	4	88	2	94	(60)	34	2	18	—	20	(15)	5
Electric commodity	—	—	—	—	—	—	—	—	2	2	(2)	—
Natural gas commodity	—	—	—	—	—	—	—	1	—	1	—	1
Total current derivative liabilities	$ 4	$ 95	$ 2	$ 101	$ (60)	41	$ 2	$ 19	$ 2	$ 23	$ (17)	6
PPAs [b]						20						23
Current derivative instruments						$ 61						$ 29
Noncurrent derivative liabilities												
Other derivative instruments:												
Commodity trading	$ —	$ 18	$ 1	$ 19	$ 17	$ 36	$ —	$ 24	$ —	$ 24	$ (10)	$ 14
Total noncurrent derivative liabilities	$ —	$ 18	$ 1	$ 19	$ 17	36	$ —	$ 24	$ —	$ 24	$ (10)	14
PPAs [b]						93						112
Noncurrent derivative instruments						$ 129						$ 126

(a) Xcel Energy nets derivative instruments and related collateral in its consolidated balance sheet when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements as of Dec. 31, 2018 and 2017. At Dec. 31, 2018 and 2017, derivative assets and liabilities include $32 million and $0 million of obligations to return cash collateral, respectively. At Dec. 31, 2018 and 2017, derivative assets and liabilities include rights to reclaim cash collateral of $15 million and $3 million, respectively. Counterparty netting excludes settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

(b) During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

Changes in Level 3 commodity derivatives:

	Year Ended Dec. 31		
(Millions of Dollars)	2018	2017	2016
Balance at Jan. 1	$ 35	$ 17	$ 18
Purchases	59	82	35
Settlements	(59)	(97)	(89)
Net transactions recorded during the period:			
(Losses) gains recognized in earnings [(a)]	(1)	5	—
Net (losses) gains recognized as regulatory assets and liabilities	(5)	28	53
Balance at Dec. 31	$ 29	$ 35	$ 17

(a) Amounts relate to commodity derivatives held at the end of the period.

Xcel Energy recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for 2016 - 2018.

Fair Value of Long-Term Debt

As of Dec. 31, other financial instruments for which the carrying amount did not equal fair value:

	2018		2017	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$ 16,209	$ 16,755	$ 14,977	$ 16,531

Fair value of Xcel Energy's long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. Fair value estimates are based on information available to management as of Dec. 31, 2018 and 2017, and given the observability of the inputs, fair values presented for long-term debt were assigned as Level 2.

11. Benefit Plans and Other Postretirement Benefits

Pension and Postretirement Health Care Benefits

Xcel Energy has several noncontributory, defined benefit pension plans that cover almost all employees. Generally, benefits are based on a combination of years of service and average pay. Xcel Energy's policy is to fully fund into an external trust the actuarially determined pension costs subject to the limitations of applicable employee benefit and tax laws.

In addition to the qualified pension plans, Xcel Energy maintains a SERP and a nonqualified pension plan. The SERP is maintained for certain executives that were participants in the plan in 2008, when the SERP was closed to new participants. The nonqualified pension plan provides benefits for compensation that is in excess of the limits applicable to the qualified pension plans, with distributions funded by Xcel Energy's consolidated operating cash flows. Obligations of the SERP and nonqualified plan as of Dec. 31, 2018 and 2017 were $33 million and $37 million, respectively. Xcel Energy recognized net benefit cost for the SERP and nonqualified plans of $4 million in 2018 and $5 million in 2017.

In 2016, Xcel Energy established rabbi trusts to provide partial funding for future distributions of the SERP and its deferred compensation plan, supplemented by Xcel Energy's consolidated operating cash flows.

Xcel Energy has a contributory health and welfare benefit plan that provides health care and death benefits to certain Xcel Energy retirees.

- NSP-Minnesota and NSP-Wisconsin discontinued subsidizing health care benefits for non-bargaining employees retiring after 1998 and for bargaining employees who retired after 1999.
- Xcel Energy discontinued subsidizing health care benefits for nonbargaining employees of the former NCE who retired after June 30, 2003.
- Xcel Energy discontinued health care benefits for SPS bargaining employees hired after Jan. 1, 2012.

Xcel Energy bases the investment-return assumption on expected long-term performance for each of the asset classes in its pension and postretirement health care portfolios. For pension assets, Xcel Energy considers the historical returns achieved by its asset portfolio over the past 20 years or longer period, as well as long-term projected return levels.

Pension cost determination assumes a forecasted mix of investment types over the long-term.

- Investment returns in 2018 were below the assumed level of 6.87%;
- Investment returns in 2017 were above the assumed level of 6.87%;
- Investment returns in 2016 were below the assumed level of 6.87%; and,
- In 2019, Xcel Energy's expected investment-return assumption is 6.87%.

Pension plan and postretirement benefit assets are invested in a portfolio according to Xcel Energy's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the asset allocation given the long-term risk, return, correlation and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any industry, index, or entity. Market volatility can impact even well-diversified portfolios and significantly affect the return levels achieved by the assets in any year.

State agencies also have issued guidelines to the funding of postretirement benefit costs. SPS is required to fund postretirement benefit costs for Texas and New Mexico amounts collected in rates. PSCo is required to fund postretirement benefit costs in irrevocable external trusts that are dedicated to the payment of these postretirement benefits. These assets are invested in a manner consistent with the investment strategy for the pension plan.

Xcel Energy's ongoing investment strategy is based on plan-specific investment recommendations that seek to minimize potential investment and interest rate risk as a plan's funded status increases over time. The investment recommendations result in a greater percentage of long-duration fixed income securities being allocated to specific plans having relatively higher funded status ratios and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios.

Plan Assets

The following presents, for each of the fair value hierarchy levels, Xcel Energy's pension plan assets measured at fair value:

(Millions of Dollars)	Dec. 31, 2018 [(a)] Level 1	Level 2	Level 3	Measured at NAV	Total	Dec. 31, 2017 [(a)] Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 137	$ —	$ —	$ —	$ 137	$ 196	$ —	$ —	$ —	$ 196
Commingled funds:	914	—	—	987	1,901	1,054	—	—	1,075	2,129
Debt securities:	—	621	—	—	621	—	673	—	—	673
Equity securities:	106	—	—	—	106	114	—	—	—	114
Other	2	5	—	(30)	(23)	(29)	4	—	1	(24)
Total	$ 1,159	$ 626	$ —	$ 957	$ 2,742	$ 1,335	$ 677	$ —	$ 1,076	$ 3,088

(a) See Note 10 for further information regarding fair value measurement inputs and methods.

The following presents, for each of the fair value hierarchy levels, Xcel Energy's postretirement benefit plan assets that were measured at fair value:

(Millions of Dollars)	Dec. 31, 2018 [(a)] Level 1	Level 2	Level 3	Measured at NAV	Total	Dec. 31, 2017 [(a)] Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 19	$ —	$ —	$ —	$ 19	$ 29	$ —	$ —	$ —	$ 29
Insurance contracts	—	45	—	—	45	—	50	—	—	50
Commingled funds	133	—	—	40	173	148	—	—	—	148
Debt securities	—	179	—	—	179	—	198	—	—	198
Equity securities	—	—	—	—	—	35	—	—	—	35
Other	—	1	—	—	1	—	1	—	—	1
Total	$ 152	$ 225	$ —	$ 40	$ 417	$ 212	$ 249	$ —	$ —	$ 461

(a) See Note 10 for further information on fair value measurement inputs and methods.

No assets were transferred in or out of Level 3 for 2018 and 2017.

Funded Status — Comparisons of the actuarially computed benefit obligation, changes in plan assets and funded status of the pension and postretirement health care plans for Xcel Energy are as follows:

(Millions of Dollars)	Pension Benefits 2018	Pension Benefits 2017	Postretirement Benefits 2018	Postretirement Benefits 2017
Change in Benefit Obligation:				
Obligation at Jan. 1	$ 3,828	$ 3,682	$ 621	$ 603
Service cost	94	94	2	2
Interest cost	133	147	22	24
Plan amendments	—	(13)	—	—
Actuarial (gain) loss	(224)	259	(62)	33
Plan participants' contributions	—	—	8	8
Medicare subsidy reimbursements	—	—	1	1
Benefit payments [(a)]	(354)	(341)	(50)	(50)
Obligation at Dec. 31	$ 3,477	$ 3,828	$ 542	$ 621
Change in Fair Value of Plan Assets:				
Fair value of plan assets at Jan. 1	$ 3,088	$ 2,856	$ 461	$ 442
Actual return on plan assets	(142)	411	(13)	41
Employer contributions	150	162	11	20
Plan participants' contributions	—	—	8	8
Benefit payments	(354)	(341)	(50)	(50)
Fair value of plan assets at Dec. 31	$ 2,742	$ 3,088	$ 417	$ 461
Funded status of plans at Dec. 31	$ (735)	$ (740)	$ (125)	$ (160)
Amounts recognized in the Consolidated Balance Sheet at Dec. 31:				
Current liabilities	$ —	$ —	$ (7)	$ (3)
Noncurrent liabilities	(735)	(740)	(118)	(157)
Net amounts recognized	$ (735)	$ (740)	$ (125)	$ (160)

(a) Includes approximately $198 million in 2018 and $174 million in 2017 of lump-sum benefit payments used in the determination of a settlement charge.

(Millions of Dollars)	Pension Benefits 2018	Pension Benefits 2017	Postretirement Benefits 2018	Postretirement Benefits 2017
Significant Assumptions Used to Measure Benefit Obligations:				
Discount rate for year-end valuation	4.31%	3.63%	4.32%	3.62%
Expected average long-term increase in compensation level	3.75	3.75	N/A	N/A
Mortality table	RP-2014	RP-2014	RP-2014	RP-2014
Health care costs trend rate — initial: Pre-65	N/A	N/A	6.50%	7.00%
Health care costs trend rate — initial: Post-65	N/A	N/A	5.35%	5.50%
Ultimate trend assumption — initial: Pre-65	N/A	N/A	4.50%	4.50%
Ultimate trend assumption — initial: Post-65	N/A	N/A	4.50%	4.50%
Years until ultimate trend is reached	N/A	N/A	4	5

Accumulated benefit obligation for the pension plan was $3,275 million and $3,612 million as of Dec. 31, 2018 and 2017, respectively.

Net Periodic Benefit Cost (Credit) — Net periodic benefit cost (credit), other than the service cost component, is included in other income in the consolidated statements of income.

Components of net periodic benefit cost (credit) and amounts recognized in other comprehensive income and regulatory assets and liabilities:

(Millions of Dollars)	Pension Benefits 2018	Pension Benefits 2017	Pension Benefits 2016	Postretirement Benefits 2018	Postretirement Benefits 2017	Postretirement Benefits 2016
Service cost	$ 94	$ 94	$ 92	$ 2	$ 2	$ 2
Interest cost	133	147	160	22	24	26
Expected return on plan assets	(209)	(209)	(210)	(26)	(25)	(25)
Amortization of prior service credit	(5)	(2)	(2)	(11)	(11)	(11)
Amortization of net loss	111	107	97	8	7	4
Settlement charge [(a)]	91	81	—	—	—	—
Net periodic pension cost (credit)	215	218	137	(5)	(3)	(4)
Costs not recognized due to effects of regulation	(75)	(79)	(15)	2	—	—
Net benefit cost (credit) recognized for financial reporting	$ 140	$ 139	$ 122	$ (3)	$ (3)	$ (4)
Significant Assumptions Used to Measure Costs:						
Discount rate	3.63%	4.13%	4.66%	3.62%	4.13%	4.65%
Expected average long-term increase in compensation level	3.75	3.75	4.00	—	—	—
Expected average long-term rate of return on assets	6.87	6.87	6.87	5.30	5.80	5.80

(a) A settlement charge is required when the amount of all lump-sum distributions during the year is greater than the sum of the service and interest cost components of the annual net periodic pension cost. In 2018 and 2017, as a result of lump-sum distributions during the 2018 and 2017 plan years, Xcel Energy recorded a total pension settlement charge of $91 million in 2018 and $81 million in 2017, the majority of which was not recognized due to the effects of regulation. A total of $11 million and $8 million was recorded in the consolidated statements of income in 2018 and 2017, respectively.

(Millions of Dollars)	Pension Benefits 2018	Pension Benefits 2017	Postretirement Benefits 2018	Postretirement Benefits 2017
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:				
Net loss	$ 1,633	$ 1,709	$ 116	$ 147
Prior service credit	(20)	(25)	(33)	(44)
Total	$ 1,613	$ 1,684	$ 83	$ 103
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:				
Current regulatory assets	$ 94	$ 100	$ —	$ —
Noncurrent regulatory assets	1,446	1,511	89	107
Current regulatory liabilities	—	—	(1)	(1)
Noncurrent regulatory liabilities	—	—	(10)	(10)
Deferred income taxes	19	19	1	2
Net-of-tax accumulated other comprehensive income	54	54	4	5
Total	$ 1,613	$ 1,684	$ 83	$ 103
Measurement date	Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017

Cash Flows — Funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the requirements of income tax and other pension-related regulations. Required contributions were made in 2016 - 2019 to meet minimum funding requirements.

Voluntary and required pension funding contributions:

- $150 million in January 2019;
- $150 million in 2018;
- $162 million in 2017; and,
- $125 million in 2016.

The postretirement health care plans have no funding requirements other than fulfilling benefit payment obligations, when claims are presented and approved. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities.

Voluntary postretirement funding contributions:

- Expects to contribute approximately $11 million during 2019;
- $11 million during 2018;
- $20 million during 2017; and,
- $18 million during 2016.

Targeted asset allocations:

	Pension Benefits		Postretirement Benefits	
	2018	2017	2018	2017
Domestic and international equity securities	36%	36%	18%	24%
Long-duration fixed income securities	30	27	—	—
Short-to-intermediate fixed income securities	17	20	70	60
Alternative investments	15	15	8	9
Cash	2	2	4	7
Total	100%	100%	100%	100%

Plan Amendments — The Xcel Energy Pension Plan and Xcel Energy Inc. Nonbargaining Pension Plan (South) were amended in 2017 to reduce supplemental benefits for non-bargaining participants as well as to allow the transfer of a portion of non-qualified pension obligations into the qualified plans. In 2016, the Xcel Energy Pension Plan was amended to change the discount rate basis for lump-sum conversion to annuity participants and annuity conversion to lump-sum participants. Annual credits contributed to the PSCo Bargaining Plan retirement spending account also increased.

In 2018 and 2017, there were no plan amendments made which affected the postretirement benefit obligation.

Projected Benefit Payments

Xcel Energy's projected benefit payments:

(Millions of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
2019	$ 281	$ 45	$ 2	$ 43
2020	260	45	2	43
2021	259	45	2	43
2022	260	44	2	42
2023	259	43	2	41
2024-2028	1,238	197	13	184

Defined Contribution Plans

Xcel Energy maintains 401(k) and other defined contribution plans that cover most employees. Total expense to these plans was approximately $38 million in 2018, $37 million in 2017 and $36 million in 2016.

Multiemployer Plans

NSP-Minnesota and NSP-Wisconsin each contribute to several union multiemployer pension and other postretirement benefit plans, none of which are individually significant. These plans provide pension and postretirement health care benefits to certain union employees who may perform services for multiple employers and do not participate in the NSP-Minnesota and NSP-Wisconsin sponsored pension and postretirement health care plans. Contributing to these types of plans creates risk that differs from providing benefits under NSP-Minnesota and NSP-Wisconsin sponsored plans, in that if another participating employer ceases to contribute to a multiemployer plan, additional unfunded obligations may need to be funded over time by remaining participating employers.

12. Commitments and Contingencies

Legal

Xcel Energy is involved in various litigation matters that are being defended and handled in the ordinary course of business. Assessing whether a loss is probable or a reasonable possibility, and whether the loss or a range of loss is estimable, often involves complex judgments regarding future events. Management maintains accruals for losses that are probable of being incurred and subject to reasonable estimation. Management may be unable to estimate an amount or range of a reasonably possible loss in certain situations, including when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Xcel Energy's financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Gas Trading Litigation — e prime is a wholly owned subsidiary of Xcel Energy. e prime was in the business of natural gas trading and marketing but has not engaged in natural gas trading or marketing activities since 2003. Multiple lawsuits seeking monetary damages were commenced against e prime and its affiliates, including Xcel Energy, between 2003 and 2009 alleging fraud and anticompetitive activities in conspiring to restrain the trade of natural gas and manipulate natural gas prices. Cases were all consolidated in the U.S. District Court in Nevada.

In the fourth quarter of 2018, four cases were settled. Two cases remain active which include an MDL matter consisting of a Colorado class (Breckenridge) and a Wisconsin class (Arandell Corp.).

Breckenridge/Colorado — Case has been remanded to the MDL panel, and is expected to be referred back to the U.S. District Court in Colorado. Xcel Energy has concluded that a loss is remote.

Arandell Corp. — In November 2017, the U.S. District Court in Nevada granted summary judgment against two plaintiffs in the Arandell Corp. case in favor of Xcel Energy and NSP-Wisconsin, leaving only three individual plaintiffs remaining in the litigation. In addition, the plaintiffs' motions for class certification and remand back to originating courts were denied in March 2017.

Plaintiffs have asked the lower court to remand the cases back to the court where the actions were originally filed anticipating class certification. A hearing date has not been set. Xcel Energy has concluded that a loss is remote.

Line Extension Disputes — In December 2015, the DRC filed a lawsuit seeking monetary damages in the Denver District Court, stating PSCo failed to award proper allowances and refunds for line extensions to new developments pursuant to the terms of electric and gas service agreements. The dispute involves claims by over fifty developers. In February 2018, the Colorado Supreme Court denied DRC's petition to appeal the Denver District Court's dismissal of the lawsuit, effectively terminating this litigation. However, in January 2018, DRC filed a new lawsuit in Boulder County District Court, asserting a single claim that PSCo was required to file its line extension agreements with the CPUC but failed to do so.

This claim is substantially similar to the arguments previously raised by DRC. PSCo filed a motion to dismiss this claim, which was granted in May 2018. DRC subsequently filed an appeal to the Colorado Court of Appeals with its opening brief in January 2019 and PSCo filed its answer brief in February 2019. It is uncertain when a decision will be rendered.

PSCo has concluded that a loss is remote with respect to both of these matters as the service agreements were developed to implement CPUC approved tariffs and PSCo has complied with the tariff provisions. If a loss were sustained, PSCo believes it would be allowed to recover costs through traditional regulatory mechanisms. Amount or range in dispute is presently unknown and no accrual has been recorded for this matter.

Rate Matters

NSP-Minnesota — Sherco — In NSP-Minnesota's 2013 fuel reconciliation filing, the MPUC made recovery of replacement power costs associated with the 2011 incident at its Sherco Unit 3 plant provisional and subject to further review following conclusion of litigation commenced by NSP-Minnesota, SMMPA (Co-owner of Sherco Unit 3) and insurance companies against GE.

In 2018, NSP-Minnesota and SMMPA reached a settlement with GE. NSP-Minnesota has notified the MPUC of its proposal to refund the GE settlement proceeds back to customers through the FCA.

The insurance providers continued their litigation against GE and the case went to trial. In 2018, GE prevailed in the lawsuit with the insurance companies, however, the jury found comparable fault, finding that GE was 52% and NSP-Minnesota was 48% at fault. At that point in the litigation, NSP-Minnesota was no longer involved in the case and was not present to make arguments about its role in the event. The specific issue leading to the fault apportionment was also not before the jury and not relevant to the outcome of the trial.

In January 2019, the DOC recommended that NSP-Minnesota refund $20 million of previously recovered purchased power costs to its customers, based on the jury's apportionment of fault. The OAG recommended the MPUC withhold any decision until the underlying litigation by the insurance providers (currently under appeal) is concluded. The DOC subsequently filed comments agreeing with the OAG's recommendation to withhold a decision pending the outcome of any appeals.

NSP-Minnesota filed reply comments arguing that the DOC recommendations are without merit and that it acted prudently in operating the plant and its settlement with GE was reasonable.

MISO ROE Complaints — In November 2013 and February 2015, customers filed complaints against MISO TOs including NSP-Minnesota and NSP-Wisconsin. The first complaint argued for a reduction in the base ROE in MISO transmission formula rates from 12.38% to 9.15%, and removal of ROE adders (including those for RTO membership). The second complaint sought to reduce base ROE from 12.38% to 8.67%.

In September 2016, the FERC issued an order granting a 10.32% base ROE (10.82% with the RTO adder) effective for the first complaint period of Nov. 12, 2013 to Feb. 11, 2015 and subsequent to the date of the order. The D.C. Circuit subsequently vacated and remanded FERC Opinion No. 531, which had established the ROE methodology on which the September 2016 FERC order was based.

In October 2018, the FERC issued a NETO base ROE order that addressed the D.C. Circuit's actions on Opinion No. 531. Under a new proposed two step ROE approach, the FERC has indicated an intention to dismiss an ROE complaint if the existing ROE falls within the range of just and reasonable ROEs based on equal weighting of the DCF, CAPM, and Expected Earnings models. The FERC proposes that if necessary, it would then set a new ROE by averaging the results of these models plus a Risk Premium model.

With respect to the MISO TOs, the FERC subsequently made preliminary determinations in a November 2018 order that the MISO base ROE in effect for the first complaint period (12.38%) was outside the range of reasonableness, and should be reduced. The FERC indicated its preliminary analysis using the new ROE approach resulted in a base ROE of 10.28% for the first compliant period, compared to the previously ordered base ROE of 10.32%. A procedural schedule has been set for the first half of 2019, with the FERC expected to act no earlier than the second half of 2019. NSP-Minnesota has recognized a current refund liability consistent with its best estimate of the final ROE.

SPP OATT Upgrade Costs — Under the SPP OATT, costs of transmission upgrades may be recovered from other SPP customers whose transmission service depends on capacity enabled by the upgrade. The SPP OATT has allowed SPP to charge for these upgrades since 2008, but SPP had not been charging its customers for these upgrades. In 2016, the FERC granted SPP's request to recover these previously unbilled charges. SPP subsequently billed SPS approximately $13 million for these charges.

In July 2018, SPS' appeal to the D.C. Circuit over the FERC rulings granting SPP the right to recover these previously unbilled charges was remanded to the FERC. Assessment of these charges (from 2008 - 2016) is being reviewed by the FERC, which is expected to rule in the first quarter of 2019.

In October 2017, SPS filed a separate complaint against SPP asserting that SPP has assessed upgrade charges to SPS in violation of the SPP OATT. The FERC has granted a rehearing for further consideration in May 2018. The timing of FERC action on the SPS rehearing is uncertain. If SPS' complaint results in additional charges or refunds, it will seek to recover or refund the differential in future rate proceedings.

Environmental

New and changing federal and state environmental mandates can create financial liabilities for Xcel Energy, which are normally recovered through the regulated rate process.

Site Remediation — Various federal and state environmental laws impose liability where hazardous substances or other regulated materials have been released to the environment. Xcel Energy Inc.'s subsidiaries may sometimes pay all or a portion of the cost to remediate sites where past activities of their predecessors or other parties have caused environmental contamination. Environmental contingencies could arise from various situations, including sites of former MGPs; and third-party sites, such as landfills, for which one or more of Xcel Energy Inc.'s subsidiaries are alleged to have sent wastes to that site.

MGP Sites

Ashland MGP Site — NSP-Wisconsin was named a responsible party for contamination at the Ashland/Northern States Power Lakefront Superfund Site (the Site) in Ashland, Wisconsin. Remediation and restoration activities are anticipated to be completed in 2019 and groundwater treatment activities will continue for many years.

Current cost estimate for remediation of the entire site is approximately $192 million, of which approximately $165 million has been spent. As of Dec. 31, 2018 and 2017, NSP-Wisconsin recorded a total liability of $27 million and $30 million, respectively, for the entire site.

NSP-Wisconsin has deferred the unrecovered portion of the estimated Site remediation costs as a regulatory asset. The PSCW has authorized NSP-Wisconsin rate recovery for all remediation costs incurred at the Site. In 2012, the PSCW agreed to allow NSP-Wisconsin to pre-collect certain costs, to amortize costs over a 10-year period and to apply a 3% carrying cost to the unamortized regulatory asset.

MGP, Landfill or Disposal Sites — Xcel Energy is currently investigating or remediating twelve MGP, landfill or other disposal sites across its service territories, in addition to the Ashland MGP Site, and these activities will continue through at least 2019. Xcel Energy accrued $9 million as of Dec. 31, 2018 and $19 million as of Dec. 31, 2017 for these sites. There may be insurance recovery and/or recovery from other potentially responsible parties, offsetting a portion of the costs incurred.

Environmental Requirements — Water and Waste

Coal Ash Regulation — Xcel Energy's operations are subject to federal and state laws that impose requirements for handling, storage, treatment and disposal of solid waste. In 2015, the EPA published the CCR Rule. Litigation was brought challenging the rule in the D.C. Circuit.

Under the CCR Rule, utilities are required to complete groundwater sampling around their CCR landfills and surface impoundments. Xcel Energy has identified at least two sites in Colorado where SSLs exist in the groundwater near landfills and/or impoundments. Xcel Energy has completed removal of CCR from these impoundments and plans to close these landfills. By the end of 2019, only nine of Xcel Energy's regulated ash units are expected to be in operation. Xcel Energy is conducting additional groundwater sampling and will evaluate whether corrective action is required at any CCR landfills or surface impoundments.

Until Xcel Energy completes its assessment, it is uncertain what impact, if any, there will be on the operations, financial condition or cash flows. In August 2018, the D.C. Circuit ruled that the EPA cannot allow utilities to continue to use unlined impoundments (including clay lined impoundments) for the storage or disposal of coal ash. Litigation is ongoing regarding the deadline for closing or retrofitting these impoundments. The decision will require Xcel Energy to expedite closure of one impoundment in Minnesota (see ARO removal costs below) and will require construction of a new impoundment, which is estimated to cost $6 million.

Federal CWA WOTUS Rule — In 2015, the EPA and Corps published a final rule that significantly broadened the scope of waters under the CWA that are subject to federal jurisdiction, referred to as "WOTUS". The Rule has been subject to significant litigation and is currently stayed in a portion of the country. Xcel Energy cannot estimate potential impacts until the legal and administrative processes are finalized, but expects costs will be recoverable through regulatory mechanisms.

Federal CWA ELG — In 2015, the EPA issued a final ELG rule for power plants that discharge treated effluent to surface waters as well as utility-owned landfills that receive CCRs. In 2017, the EPA delayed the compliance date for flue gas desulfurization wastewater and bottom ash transport until November 2020. After 2020, Xcel Energy estimates that ELG compliance will cost approximately $12 million to complete. The EPA, however, is conducting a rulemaking process to potentially revise the effluent limitations and pretreatment standards, which may impact compliance costs. Xcel Energy anticipates these costs will be fully recoverable through regulatory mechanisms.

Federal CWA Section 316(b) — The federal CWA requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available for minimizing impingement and entrainment of aquatic species. Xcel Energy estimates the likely cost for complying with impingement and entrainment requirements is approximately $40 million, to be incurred between 2019 and 2028. Xcel Energy believes six NSP-Minnesota plants and two NSP-Wisconsin plants could be required by state regulators to make improvements to reduce impingement and entrainment. The exact total cost of the impingement and entrainment improvements is uncertain, but could be up to approximately $200 million. Xcel Energy anticipates these costs will be fully recoverable through regulatory mechanisms.

Environmental Requirements — Air

Regional Haze Rules — The regional haze program requires SO_2, NO_X and PM emission controls at power plants to reduce visibility impairment in national parks and wilderness areas. The program includes BART and reasonable further progress.

The requirements of the first regional haze plans developed by Minnesota and Colorado have been approved and implemented. Texas' first regional haze plan has undergone federal review as described below.

BART Determination for Texas: The EPA has issued a revised final rule adopting a BART alternative Texas only SO_2 trading program that applies to all Harrington and Tolk units. Under the trading program, SPS expects the allowance allocations to be sufficient for SO_2 emissions. The anticipated costs of compliance are not expected to have a material impact; and SPS believes that compliance costs would be recoverable through regulatory mechanisms.

Several parties have challenged whether the final rule issued by the EPA should be considered to have met the requirements imposed in a Consent Decree entered by the United States District Court for the District of Columbia that established deadlines for the EPA to take final action on state regional haze plan submissions. The court has required status reports from the parties while the EPA works on the reconsideration rulemaking.

In December 2017, the National Parks Conservation Association, Sierra Club, and Environmental Defense Fund appealed the EPA's 2017 final BART rule to the Fifth Circuit and filed a petition for administrative reconsideration. In January 2018, the court granted SPS' motion to intervene in the Fifth Circuit litigation in support of the EPA's final rule. The court has held the litigation in abeyance while the EPA decided whether to reconsider the rule. In August 2018, the EPA started a reconsideration rulemaking. It is not known when the EPA will make a final decision on this proposal.

Reasonable Progress Rule: In 2016, the EPA adopted a final rule establishing a federal implementation plan for reasonable further progress under the regional haze program for the state of Texas. The rule imposes SO_2 emission limitations that would require the installation of dry scrubbers on Tolk Units 1 and 2, with compliance required by February 2021. Investment costs associated with dry scrubbers could be $600 million. SPS appealed the EPA's decision and obtained a stay of the final rule.

In March 2017, the Fifth Circuit remanded the rule to the EPA for reconsideration, leaving the stay in effect. In a future rulemaking, the EPA will address whether SO_2 emission reductions beyond those required in the BART alternative rule are needed at Tolk under the "reasonable progress" requirements. The EPA has not announced a schedule for acting on the remanded rule.

Implementation of the NAAQS for SO_2 — The EPA has designated all areas near SPS' generating plants as attaining the SO_2 NAAQS with an exception. The EPA issued final designations which found the area near the SPS Harrington plant as "unclassifiable." The area near the Harrington plant is to be monitored for three years and a final designation is expected to be made by December 2020.

If the area near the Harrington plant is designated nonattainment in 2020, the TCEQ will need to develop an implementation plan, designed to achieve the NAAQS by 2025. The TCEQ could require additional SO_2 controls at Harrington as part of such a plan. Xcel Energy cannot evaluate the impacts until the final designation is made and any required state plans are developed. Xcel Energy believes that should SO_2 control systems be required for a plant, compliance costs or the costs of alternative cost-effective generation will be recoverable through regulatory mechanisms and therefore does not expect a material impact on results of operations, financial condition or cash flows.

AROs — AROs have been recorded for Xcel Energy's assets. For nuclear assets, the ARO is associated with the decommissioning of the NSP-Minnesota nuclear generating plants, Monticello and PI.

Aggregate fair value of NSP-Minnesota's legally restricted assets, for funding future nuclear decommissioning, was $2.1 billion for 2018 and 2017.

Xcel Energy's AROs were as follows:

	Dec. 31, 2018					
(Millions of Dollars)	Jan. 1, 2018	Amounts Incurred (a)	Amounts Settled (b)	Accretion	Cash Flow Revisions (c)	Dec. 31, 2018
Electric						
Nuclear	$1,874	$ —	$ —	$ 94	$ —	$1,968
Steam, hydro, and other production	192	—	(14)	8	(9)	177
Wind	96	12	—	4	7	119
Distribution	21	—	—	1	20	42
Miscellaneous	5	—	—	—	2	7
Natural gas						
Transmission and distribution	282	—	—	13	(46)	249
Miscellaneous	4	—	—	—	—	4
Common						
Miscellaneous	1	—	—	—	—	1
Non-utility						
Miscellaneous	—	1	—	—	—	1
Total liability	$2,475	$ 13	$ (14)	$ 120	$ (26)	$2,568

(a) Amounts incurred related to the PSCo Rush Creek wind farm and Nicollet Projects community solar gardens, which were placed in service in 2018.

(b) Amounts settled related to asbestos abatement projects and closure of certain ash containment facilities.

(c) In 2018, AROs were revised for changes in timing and estimates of cash flows. Changes in gas transmission and distribution AROs were primarily related to increased gas line mileage and number of services, which were more than offset by increased discount rates. Changes in electric distribution AROs primarily related to increased labor costs.

	Dec. 31, 2017					
(Millions of Dollars)	Jan. 1, 2017	Amounts Incurred	Amounts Settled (a)	Accretion	Cash Flow Revisions (b)	Dec. 31, 2017
Electric						
Nuclear	$2,249	$ —	$ —	$ 114	$ (489)	$1,874
Steam, hydro, and other production	205	1	(29)	9	6	192
Wind	92	—	—	4	—	96
Distribution	20	—	—	1	—	21
Miscellaneous	5	—	—	—	—	5
Natural gas						
Transmission and distribution	205	—	—	8	69	282
Miscellaneous	4	—	—	—	—	4
Common						
Miscellaneous	2	—	(1)	—	—	1
Total liability	$2,782	$ 1	$ (30)	$ 136	$ (414)	$2,475

(a) Amounts settled related to asbestos abatement, closure of ash containment facilities, and removal and disposal of storage tanks and other above ground equipment.

(b) In 2017, AROs were revised for changes in timing and estimates of cash flows. Nuclear AROs decreased due to updated assumptions. Changes in gas transmission and distribution AROs were primarily related to increased labor costs.

Indeterminate AROs — Other plants or buildings may contain asbestos due to the age of many of Xcel Energy's facilities, but no confirmation or measurement of the cost of removal could be determined as of Dec. 31, 2018. Therefore, an ARO was not recorded for these facilities.

Removal Costs — Xcel Energy records a regulatory liability for the plant removal costs of its utility subsidiaries that are recovered currently in rates. Removal costs have accumulated based on varying rates as authorized by the appropriate regulatory entities. The utility subsidiaries have estimated the amount of removal costs accumulated through historic depreciation expense based on current factors used in the existing depreciation rates.

Accumulated balances by entity at Dec. 31:

(Millions of Dollars)	2018	2017
NSP-Minnesota	$ 485	$ 442
PSCo	344	346
SPS	188	197
NSP-Wisconsin	158	146
Total Xcel Energy	$ 1,175	$ 1,131

Nuclear Related

Nuclear Insurance — NSP-Minnesota's public liability for claims from any nuclear incident is limited to $14.1 billion under the Price-Anderson amendment to the Atomic Energy Act. NSP-Minnesota has secured $450 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $13.6 billion of exposure is funded by the Secondary Financial Protection Program, available from assessments by the federal government.

NSP-Minnesota is subject to assessments of up to $138 million per reactor-incident for each of its three licensed reactors, for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is $21 million per reactor-incident during any one year. Maximum assessments are subject to inflation adjustments by the NRC and state premium taxes. The NRC's last adjustment was effective November 2018.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from NEIL and EMANI. The coverage limits are $2.3 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage, including the cost of replacement power during prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term.

All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL and EMANI to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage. NSP-Minnesota could be subject to annual maximum assessments of approximately $18 million for business interruption insurance and $39 million for property damage insurance if losses exceed accumulated reserve funds.

Nuclear Fuel Disposal — NSP-Minnesota is responsible for temporarily storing spent nuclear fuel from its nuclear plants. The DOE is responsible for permanently storing spent fuel from U.S. nuclear plants, but no such facility is yet available.

NSP-Minnesota owns temporary on-site storage facilities for spent fuel at its Monticello and PI nuclear plants, which consist of storage pools and dry cask facilities. The Monticello dry-cask storage facility currently stores all 30 of the authorized canisters. The PI dry-cask storage facility currently stores 44 of the 64 authorized casks. Monticello's future spent fuel will continue to be placed in its spent fuel pool. The decommissioning plan addresses the disposition of spent fuel at the end of the licensed life.

Regulatory Plant Decommissioning Recovery — Decommissioning activities for NSP-Minnesota's nuclear facilities are planned to begin at the end of each unit's operating license and be completed by 2091. NSP-Minnesota's current operating licenses allow continued use of its Monticello nuclear plant until 2030 and its PI nuclear plant until 2033 for Unit 1 and 2034 for Unit 2.

Future decommissioning costs of nuclear facilities are estimated through triennial periodic studies that assess the costs and timing of planned nuclear decommissioning activities for each unit.

Obligation for decommissioning is expected to be funded 100% by the external decommissioning trust fund. This cost study assumes the external decommissioning fund will earn an after-tax return between 5.23% and 6.30% Realized and unrealized gains on fund investments are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Decommissioning costs are quantified in 2014 dollars. Escalation rates are 4.36% for plant removal activities and 3.36% for fuel management and site restoration activities.

NSP-Minnesota has accumulated $2.1 billion of assets held in external decommissioning trusts in 2018. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation. Xcel Energy believes future decommissioning costs will continue to be recovered in customer rates. The following amounts were prepared on a regulatory basis and not directly recorded in the financial statements (ARO).

	Regulatory Basis	
(Millions of Dollars)	2018	2017
Estimated decommissioning cost obligation from most recently approved study (in 2014 dollars)	$ 3,012	$ 3,012
Effect of escalating costs	539	396
Estimated decommissioning cost obligation (in current dollars)	3,551	3,408
Effect of escalating costs to payment date	7,654	7,797
Estimated future decommissioning costs (undiscounted)	11,205	11,205
Effect of discounting obligation (using average risk-free interest rate of 3.33% and 2.80% for 2018 and 2017, respectively)	(6,911)	(6,398)
Discounted decommissioning cost obligation	$ 4,294	$ 4,807
Assets held in external decommissioning trust	$ 2,055	$ 2,143
Underfunding of external decommissioning fund compared to the discounted decommissioning obligation	2,239	2,664

Calculations and data used by the regulator in approving NSP-Minnesota's rates are useful in assessing future cash flows. Regulatory basis information is a means to reconcile amounts previously provided to the MPUC and utilized for regulatory purposes to amounts used for financial reporting.

Reconciliation of the discounted decommissioning cost obligation - regulated basis to the ARO recorded in accordance with GAAP:

(Millions of Dollars)	2018	2017
Discounted decommissioning cost obligation - regulated basis	$ 4,294	$ 4,807
Differences in discount rate and market risk premium	(1,447)	(1,403)
O&M costs not included for GAAP	(879)	(1,041)
ARO differences between 2017 and 2014 cost studies	—	(489)
Nuclear production decommissioning ARO - GAAP	$ 1,968	$ 1,874

Decommissioning expenses recognized as a result of regulation:

(Millions of Dollars)	2018	2017	2016
Annual decommissioning recorded as depreciation expense: [(a)] [(b)]	$ 20	$ 20	$ 20

(a) Decommissioning expense does not include depreciation of the capitalized nuclear asset retirement costs.

(b) Decommissioning expenses in 2018, 2017 and 2016 include Minnesota's retail jurisdiction annual funding requirement of approximately $14 million.

The 2014 nuclear decommissioning filing, approved in 2015, was used for regulatory presentation in 2018, 2017 and 2016. The 2017 filing, effective Jan. 1, 2019, has been approved by the MPUC.

Leases — Xcel Energy has three leases accounted for as capital leases. The assets and liabilities of a capital lease are recorded at the lower of fair market value of the leased asset or the present value of future lease payments and are amortized over the term of the contract.

WYCO is a joint venture with CIG to develop and lease natural gas pipeline, storage and compression facilities. Xcel Energy Inc. has a 50% ownership interest in WYCO. WYCO leases its facilities to CIG, and CIG operates the facilities, providing natural gas storage and transportation services to PSCo under separate service agreements.

PSCo accounts for its Totem natural gas storage service arrangement with CIG as a capital lease. Xcel Energy Inc. eliminates 50% of the capital lease obligation related to WYCO in the consolidated balance sheet along with an equal amount of Xcel Energy Inc.'s equity investment in WYCO.

PSCo records amortization for its capital lease assets as electric fuel and purchased power and cost of natural gas sold and transported on the consolidated statements of income.

Property held under capital leases:

(Millions of Dollars)	Dec. 31, 2018	Dec. 31, 2017
Gas storage facilities	$ 201	$ 201
Gas pipeline	21	21
Property held under capital leases	222	222
Accumulated depreciation	(77)	(71)
Total property held under capital leases, net	$ 145	$ 151

Remaining leases, primarily for real estate and certain natural gas generating facilities operated under PPAs, as well as railcars, aircraft and other equipment, are accounted for as operating leases.

Total expenses (including capacity payments) under operating lease obligations for Xcel Energy and the corresponding capacity payments for PPAs accounted for as operating leases for the year ended Dec. 31:

(Millions of Dollars)	2018	2017	2016
Total expense	$ 248	$ 246	$ 255
Capacity payments	210	210	216

Included in the future commitments under operating leases are estimated future capacity payments under PPAs that have been accounted for as operating leases.

Future commitments under operating and capital leases:

(Millions of Dollars)	Operating Leases	PPA [a] [b] Operating Leases	Total Operating Leases	Capital Leases
2019	$ 32	$ 207	$ 239	$ 14
2020	26	208	234	14
2021	25	210	235	14
2022	24	197	221	12
2023	22	186	208	12
Thereafter	154	883	1,037	220
Total minimum obligation				286
Interest component of obligation				(201)
Present value of minimum obligation				$ 85 [c]

(a) Amounts do not include PPAs accounted for as executory contracts.

(b) PPA operating leases contractually expire through 2034.

(c) Excludes certain amounts related to Xcel Energy's 50% ownership interest in WYCO.

Non-Lease PPAs — NSP Minnesota, PSCo and SPS have entered into PPAs with other utilities and energy suppliers with expiration dates through 2039 for purchased power to meet system load and energy requirements, meet operating reserve obligations and as part of wholesale and commodity trading activities. In general, these agreements provide for energy payments, based on actual energy delivered and capacity payments. Certain PPAs accounted for as executory contracts contain minimum energy purchase commitments. Capacity and energy payments are contingent on the IPPs meeting contract obligations, including plant availability requirements. Certain contractual payments are adjusted based on market indices. The effects of price adjustments on our financial results are mitigated through purchased energy cost recovery mechanisms.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts were payments for capacity of $131 million, $168 million and $191 million in 2018, 2017 and 2016, respectively.

At Dec. 31, 2018, the estimated future payments for capacity and energy that the utility subsidiaries of Xcel Energy are obligated to purchase pursuant to these executory contracts, subject to availability, were as follows:

(Millions of Dollars)	Capacity	Energy [a]
2019	$ 86	$ 99
2020	70	109
2021	78	157
2022	77	173
2023	79	177
Thereafter	125	328
Total	$ 515	$ 1,043

(a) Excludes contingent energy payments for renewable energy PPAs.

Fuel Contracts — Xcel Energy has entered into various long-term commitments for the purchase and delivery of a significant portion of its coal, nuclear fuel and natural gas requirements. These contracts expire between 2019 and 2060. Xcel Energy is required to pay additional amounts depending on actual quantities shipped under these agreements.

Estimated minimum purchases under these contracts as of Dec. 31, 2018:

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas supply	Natural gas supply and transportation
2019	$ 461	$ 127	$ 416	$ 268
2020	260	51	263	255
2021	149	99	254	245
2022	109	79	114	234
2023	61	99	60	170
Thereafter	108	337	—	923
Total	$ 1,148	$ 792	$ 1,107	$ 2,095

VIEs

PPAs — Under certain PPAs, NSP-Minnesota, PSCo and SPS purchase power from IPPs for which the utility subsidiaries are required to reimburse fuel costs, or to participate in tolling arrangements under which the utility subsidiaries procure the natural gas required to produce the energy that they purchase. Xcel Energy has determined that certain IPPs are VIEs. Xcel Energy is not subject to risk of loss from the operations of these entities, and no significant financial support is required other than contractual payments for energy and capacity.

In addition, certain solar PPAs provide an option to purchase emission allowances or sharing provisions related to production credits generated by the solar facility under contract. These specific PPAs create a variable interest in the IPP.

Xcel Energy evaluated each of these VIEs for possible consolidation, including review of qualitative factors such as the length and terms of the contract, control over O&M, control over dispatch of electricity, historical and estimated future fuel and electricity prices, and financing activities.

Xcel Energy concluded that these entities are not required to be consolidated in its consolidated financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance. Xcel Energy's utility subsidiaries had approximately 3,770 MW and 3,537 MW of capacity under long-term PPAs at Dec. 31, 2018 and 2017, respectively, with entities that have been determined to be VIEs. Agreements have expiration dates through 2041.

Fuel Contracts — SPS purchases all of its coal requirements for its Harrington and Tolk plants from TUCO under contracts that will expire in December 2022. TUCO arranges for the purchase, receiving, transporting, unloading, handling, crushing, weighing and delivery of coal to meet SPS' requirements. TUCO is responsible for negotiating and administering contracts with coal suppliers, transporters and handlers.

SPS has not provided any significant financial support to TUCO, other than contractual payments for delivered coal. However, the fuel contracts create a variable interest in TUCO due to SPS' reimbursement of fuel procurement costs. SPS has determined that TUCO is a VIE. SPS has concluded that it is not the primary beneficiary of TUCO because SPS does not have the power to direct the activities that most significantly impact TUCO's economic performance.

Low-Income Housing Limited Partnerships — Eloigne and NSP-Wisconsin have entered into limited partnerships for the construction and operation of affordable rental housing developments which qualify for low-income housing tax credits. Xcel Energy Inc. has determined Eloigne and NSP-Wisconsin's low-income housing partnerships to be VIEs primarily due to contractual arrangements within each limited partnership that establish sharing of ongoing voting control and profits and losses that does not align with the partners' proportional equity ownership. Eloigne and NSP-Wisconsin have the power to direct the activities that most significantly impact these entities' economic performance. Therefore, Xcel Energy Inc. consolidates these limited partnerships in its consolidated financial statements. Xcel Energy's risk of loss for these partnerships is limited to its capital contributions, adjusted for any distributions and its share of undistributed profits and losses; no significant additional financial support has been, or is required to be provided to the limited partnerships by Eloigne or NSP-Wisconsin.

Amounts reflected in Xcel Energy's consolidated balance sheets for the Eloigne and NSP-Wisconsin low-income housing limited partnerships:

(Millions of Dollars)	Dec. 31, 2018	Dec. 31, 2017
Current assets	$ 5	$ 6
Property, plant and equipment, net	42	46
Other noncurrent assets	1	1
Total assets	$ 48	$ 53
Current liabilities	$ 7	$ 9
Mortgages and other long-term debt payable	26	26
Other noncurrent liabilities	—	1
Total liabilities	$ 33	$ 36

Other

Technology Agreements — Xcel Energy has a contract that extends through December 2022 with IBM for information technology services. Contract is cancelable at Xcel Energy's option, although Xcel Energy would be obligated to pay 50% of the contract value for early termination. Xcel Energy capitalized or expensed $81 million, $98 million and $119 million associated with the IBM contract in 2018, 2017 and 2016, respectively.

Xcel Energy's contract with Accenture for information technology services extends through December 2020. Contract is cancelable at Xcel Energy's option, although there are financial penalties for early termination. Xcel Energy capitalized or expensed $46 million, $16 million and $35 million associated with the Accenture contract in 2018, 2017 and 2016, respectively.

Committed minimum payments under these obligations:

(Millions of Dollars)	IBM Agreement	Accenture Agreement
2019	$ 30	$ 11
2020	16	11
2021	16	—
2022	7	—
2023	—	—
Thereafter	—	—

Guarantees and Bond Indemnifications — Xcel Energy Inc. and its subsidiaries enter into contractual guarantees in limited circumstances. Xcel Energy Inc. may guarantee the subsidiaries' obligations in the event they fail to perform and may provide guarantees in certain indemnification agreements. Xcel Energy Inc.'s guarantees from the subsidiaries are not individually material with maximum potential liability totaling $6 million as of Dec. 31, 2018. Payment for these guarantees is considered remote.

13. Other Comprehensive Income

Changes in accumulated other comprehensive (loss), net of tax, for the years ended Dec. 31:

	2018		
(Millions of Dollars)	Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (58)	$ (67)	$ (125)
Other comprehensive loss before reclassifications (net of taxes of $(2) and $(2), respectively)	(5)	(6)	(11)
Losses reclassified from net accumulated other comprehensive loss:			
Interest rate derivatives (net of taxes of $1 and $0, respectively)	3 (a)	—	3
Amortization of net actuarial loss (net of taxes of $0 and $3, respectively)	—	9 (b)	9
Net current period other comprehensive income (loss)	(2)	3	1
Accumulated other comprehensive loss at Dec. 31	$ (60)	$ (64)	$ (124)

(Millions of Dollars)	2017 Gains and Losses on Cash Flow Hedges		2017 Defined Benefit Pension and Postretirement Items		2017 Total
Accumulated other comprehensive loss at Jan. 1	$ (51)		$ (59)		$ (110)
Other comprehensive loss before reclassifications (net of taxes of $0 and $(2), respectively)	—		(3)		(3)
Losses reclassified from net accumulated other comprehensive loss:					
Interest rate derivatives (net of taxes of $2 and $0, respectively)	3	(a)	—		3
Amortization of net actuarial loss (net of taxes of $0 and $5, respectively)	—		7	(b)	$ 7
Net current period other comprehensive income	3		4		7
Adoption of ASU No. 2018-02 (c)	(10)		(12)		(22)
Accumulated other comprehensive loss at Dec. 31	$ (58)		$ (67)		$ (125)

(a) Included in interest charges.

(b) Included in the computation of net periodic pension and postretirement benefit costs.

(c) In 2017, Xcel Energy implemented ASU No. 2018-02 related to the TCJA, which resulted in reclassification of certain credit balances within net accumulated other comprehensive loss to retained earnings.

14. Segments and Related Information

Regulated electric utility operating results of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, as well as the regulated natural gas utility operating results of NSP-Minnesota, NSP-Wisconsin and PSCo are each separately and regularly reviewed by Xcel Energy's chief operating decision maker. Xcel Energy evaluates performance by each utility subsidiary based on profit or loss generated from the product or service provided. These segments are managed separately because the revenue streams are dependent upon regulated rate recovery, which is separately determined for each segment.

Xcel Energy has the following reportable segments:

- *Regulated Electric* - The regulated electric utility segment generates, transmits and distributes electricity in Minnesota, Wisconsin, Michigan, North Dakota, South Dakota, Colorado, Texas and New Mexico. In addition, this segment includes sales for resale and provides wholesale transmission service to various entities in the United States. The regulated electric utility segment also includes wholesale commodity and trading operations.
- *Regulated Natural Gas* - The regulated natural gas utility segment transports, stores and distributes natural gas primarily in portions of Minnesota, Wisconsin, North Dakota, Michigan and Colorado.
- *All Other* - Operating segments with revenues below the necessary quantitative thresholds are included in this category. Those segments primarily include steam revenue, appliance repair services, non-utility real estate activities, revenues associated with processing solid waste into refuse-derived fuel and investments in rental housing projects that qualify for low-income housing tax credits.

Xcel Energy had equity investments in unconsolidated subsidiaries of $141 million and $140 million as of Dec. 31, 2018 and 2017, respectively, included in the natural gas utility and all other segments.

Asset and capital expenditure information is not provided for Xcel Energy's reportable segments. As an integrated electric and natural gas utility, Xcel Energy operates significant assets that are not dedicated to a specific business segment. Reporting assets and capital expenditures by business segment would require arbitrary and potentially misleading allocations which may not necessarily reflect the assets that would be required for the operation of the business segments on a stand-alone basis.

Certain costs, such as common depreciation, common O&M expenses and interest expense are allocated based on cost causation allocators across each segment. In addition, a general allocator is used for certain general and administrative expenses, including office supplies, rent, property insurance and general advertising.

Xcel Energy's segment information:

(Millions of Dollars)	2018	2017	2016
Regulated Electric			
Operating revenues from external customers	$ 9,719	$ 9,676	$ 9,500
Intersegment revenue	1	2	1
Total revenues	$ 9,720	$ 9,678	$ 9,501
Depreciation and amortization	1,421	1,298	1,136
Interest charges and financing costs	449	449	450
Income tax expense	187	528	567
Net income	1,177	1,066	1,067
Regulated Natural Gas			
Operating revenues from external customers	$ 1,739	$ 1,650	$ 1,531
Intersegment revenue	2	1	1
Total revenues	$ 1,741	$ 1,651	$ 1,532
Depreciation and amortization	212	174	160
Interest charges and financing costs	61	57	54
Income tax expense	28	23	76
Net income	187	182	124
All Other			
Total operating revenue	$ 79	$ 78	$ 76
Depreciation and amortization	9	7	7
Interest charges and financing costs	142	122	116
Income tax (benefit)	(34)	(9)	(62)
Net (loss)	(103)	(100)	(68)
Consolidated Total			
Total revenue	$ 11,540	$ 11,407	$ 11,109
Reconciling eliminations	(3)	(3)	(2)
Consolidated total revenue	$ 11,537	$ 11,404	$ 11,107
Depreciation and amortization	1,642	1,479	1,303
Interest charges and financing costs	652	628	620
Income tax expense	181	542	581
Net income	1,261	1,148	1,123

15. Summarized Quarterly Financial Data (Unaudited)

(Amounts in millions, except per share data)	Quarter Ended March 31, 2018	June 30, 2018	Sept. 30, 2018	Dec. 31, 2018
Operating revenues	$ 2,951	$ 2,658	$ 3,048	$ 2,880
Operating income [(a)]	480	450	696	339
Net income	291	265	491	214
EPS total — basic	$ 0.57	$ 0.52	$ 0.96	$ 0.42
EPS total — diluted	0.57	0.52	0.96	0.42
Cash dividends declared per common share	0.38	0.38	0.38	0.38

(Amounts in millions, except per share data)	Quarter Ended March 31, 2017	June 30, 2017	Sept. 30, 2017	Dec. 31, 2017
Operating revenues	$ 2,946	$ 2,645	$ 3,017	$ 2,796
Operating income [(a)]	492	466	824	440
Net income	239	227	492	189
EPS total — basic	$ 0.47	$ 0.45	$ 0.97	$ 0.37
EPS total — diluted	0.47	0.45	0.97	0.37
Cash dividends declared per common share	0.36	0.36	0.36	0.36

(a) In 2018, Xcel Energy implemented ASU No. 2017-07 related to net periodic benefit cost, which resulted in retrospective reclassification of pension costs from O&M expense to other income.

Item 9 — Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A — Controls and Procedures

Disclosure Controls and Procedures

Xcel Energy maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer and chief financial officer, allowing timely decisions regarding required disclosure. As of Dec. 31, 2018, based on an evaluation carried out under the supervision and with the participation of Xcel Energy's management, including the chief executive officer and chief financial officer, of the effectiveness of its disclosure controls and the procedures, the chief executive officer and chief financial officer have concluded that Xcel Energy's disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

No change in Xcel Energy's internal control over financial reporting has occurred during the most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, Xcel Energy's internal control over financial reporting. Xcel Energy maintains internal control over financial reporting to provide reasonable assurance regarding the reliability of the financial reporting.

Xcel Energy has evaluated and documented its controls in process activities, general computer activities, and on an entity-wide level. During the year and in preparation for issuing its report for the year ended Dec. 31, 2018 on internal controls under section 404 of the Sarbanes-Oxley Act of 2002, Xcel Energy conducted testing and monitoring of its internal control over financial reporting. Based on the control evaluation, testing and remediation performed, Xcel Energy did not identify any material control weaknesses, as defined under the standards and rules issued by the Public Company Accounting Oversight Board and as approved by the SEC and as indicated in Management Report on Internal Controls herein.

Item 9B — Other Information

None.

PART III

Item 10 — Directors, Executive Officers and Corporate Governance

Information required under this Item with respect to Directors and Corporate Governance is set forth in Xcel Energy Inc.'s Proxy Statement for its 2019 Annual Meeting of Shareholders, which is incorporated by reference. Information with respect to Executive Officers is included in Item 1 to this report.

Item 11 — Executive Compensation

Information required under this Item is set forth in Xcel Energy Inc.'s Proxy Statement for its 2019 Annual Meeting of Shareholders, which is incorporated by reference.

Item 12 — Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required under this Item is contained in Xcel Energy Inc.'s Proxy Statement for its 2019 Annual Meeting of Shareholders, which is incorporated by reference.

Item 13 — Certain Relationships and Related Transactions, and Director Independence

Information required under this Item is contained in Xcel Energy Inc.'s Proxy Statement for its 2019 Annual Meeting of Shareholders, which is incorporated by reference.

Item 14 — Principal Accountant Fees and Services

Information required under this Item is contained in Xcel Energy Inc.'s Proxy Statement for its 2019 Annual Meeting of Shareholders, which is incorporated by reference.

PART IV

Item 15 — Exhibits, Financial Statement Schedules

1	Consolidated Financial Statements
	Management Report on Internal Controls Over Financial Reporting — For the year ended Dec. 31, 2018.
	Report of Independent Registered Public Accounting Firm — Financial Statements
	Report of Independent Registered Public Accounting Firm — Internal Controls Over Financial Reporting
	Consolidated Statements of Income — For the three years ended Dec. 31, 2018, 2017, and 2016.
	Consolidated Statements of Comprehensive Income — For the three years ended Dec. 31, 2018, 2017, and 2016.
	Consolidated Statements of Cash Flows — For the three years ended Dec. 31, 2018, 2017, and 2016.
	Consolidated Balance Sheets — As of Dec. 31, 2018 and 2017.
	Consolidated Statements of Common Stockholders' Equity — For the three years ended Dec. 31, 2018, 2017, and 2016.
2	Schedule I — Condensed Financial Information of Registrant.
	Schedule II — Valuation and Qualifying Accounts and Reserves for the years ended Dec. 31, 2018, 2017 and 2016.
3	Exhibits
*	Indicates incorporation by reference
+	Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors

Xcel Energy Inc.

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
3.01*	Amended and Restated Articles of Incorporation of Xcel Energy Inc.	Xcel Energy Inc Form 8-K dated May 16, 2012	001-03034	3.01
3.02*	Bylaws of Xcel Energy Inc.	Xcel Energy Inc Form 8-K dated Feb. 17, 2016	001-03034	3.01
4.01*	Indenture dated Dec. 1, 2000 between Xcel Energy Inc. and Wells Fargo Bank Minnesota, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated Dec. 14, 2000	001-03034	4.01
4.02*	Supplemental Indenture No. 3 dated June 1, 2006 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated June 6, 2006	001-03034	4.01
4.03*	Junior Subordinated Indenture, dated as of Jan. 1, 2008, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated Jan. 16, 2008	001-03034	4.01
4.04*	Replacement Capital Covenant, dated Jan. 16, 2008	Xcel Energy Inc. Form 8-K dated Jan. 16, 2008	001-03034	4.03
4.05*	Supplemental Indenture No. 5, dated as of May 1, 2010 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated May 10, 2010	001-03034	4.01
4.06*	Supplemental Indenture No. 6, dated as of Sept. 1, 2011 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated Sept. 12, 2011	001-03034	4.01
4.07*	Supplemental Indenture No. 8, dated as of June 1, 2015 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated June 1, 2015	001-03034	4.01
4.08*	Supplemental Indenture No. 9, dated as of March 1, 2016, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated March 8, 2016	001-03034	4.02
4.09*	Supplemental Indenture No. 10, dated as of Dec. 1, 2016, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated Dec. 1, 2016	001-03034	4.01
4.10*	Supplemental Indenture No. 11, dated as of June 25, 2018, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated June 25, 2018	001-03034	4.01
10.01*	Xcel Energy Inc. Nonqualified Pension Plan (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.02
10.02*+	Xcel Energy Senior Executive Severance and Change-in-Control Policy (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.05
10.03*+	Xcel Energy Inc. Non-Employee Directors Deferred Compensation Plan as amended and restated Jan. 1, 2009	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.08
10.04*+	Form of Services Agreement between Xcel Energy Services Inc. and utility companies	Xcel Energy Inc. Form U5B dated Nov. 16, 2000	001-03034	H-1
10.05*+	Xcel Energy Inc. Supplemental Executive Retirement Plan as amended and restated Jan. 1, 2009	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.17
10.06*+	First Amendment to Exhibit 10.02 dated Aug. 26, 2009	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2009	001-03034	10.06
10.07*+	Xcel Energy Inc. Executive Annual Incentive Award Plan Form of Restricted Stock Agreement	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2009	001-03034	10.08
10.08*+	Xcel Energy Inc. Executive Annual Incentive Plan (as amended and restated effective Feb. 17, 2010)	Xcel Energy Inc. Definitive Proxy Statement dated April 6, 2010	001-03034	Schedule 14A

10.09*+	Xcel Energy Inc. 2005 Long-Term Incentive Plan (as amended and restated effective Feb. 17, 2010)	Xcel Energy Inc. Definitive Proxy Statement dated April 6, 2010	001-03034	Schedule 14A
10.10*+	Stock Equivalent Plan for Non-Employee Directors of Xcel Energy Inc. as amended and restated effective Feb. 23, 2011	Xcel Energy Inc. Definitive Proxy Statement dated April 5, 2011	001-03034	Schedule 14A
10.11*+	Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.07
10.12*+	First Amendment to Exhibit 10.11 effective Nov. 29, 2011	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2011	001-03034	10.17
10.13*+	Second Amendment to Exhibit 10.02 dated Oct. 26, 2011	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2011	001-03034	10.18
10.14*+	First Amendment to Exhibit 10.08 dated Feb. 20, 2013	Xcel Energy Inc. Form 10-Q for the quarter ended March 31, 2013	001-03034	10.01
10.15*+	Fourth Amendment to Exhibit 10.02 dated Feb. 20, 2013	Xcel Energy Inc. Form 10-Q for the quarter ended March 31, 2013	001-03034	10.02
10.16*+	First Amendment to Exhibit 10.09 dated May 21, 2013	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2013	001-03034	10.21
10.17*+	Second Amendment to Exhibit 10.11 dated May 21, 2013	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2013	001-03034	10.22
10.18*+	Xcel Energy Inc. 2005 Long-Term Incentive Plan Form of Long-Term Incentive Award Agreement	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2013	001-03034	10.23
10.19*+	Xcel Energy Inc. 2015 Omnibus Incentive Plan	Xcel Energy Inc. Definitive Proxy Statement dated April 6, 2015	001-03034	Schedule 14A
10.20*+	Stock Equivalent Program for Non-Employee Directors of Xcel Energy Inc. under the Xcel Energy Inc. 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 8-K dated May 20, 2015	001-03034	10.02
10.21*	Form of Xcel Energy Inc. 2015 Omnibus Incentive Plan Award Agreement and Award Terms and Conditions under the Xcel Energy Inc. 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 8-K dated May 20, 2015	001-03034	10.03
10.22*+	Xcel Energy Inc. 2015 Omnibus Incentive Plan Form of Award Agreement	Xcel Energy inc. Form 10-K for the year ended Dec. 31, 2015	001-03034	10.28
10.23*+	Xcel Energy Inc. Executive Annual Incentive Award Sub-plan pursuant to the Xcel Energy Inc. 2015 Omnibus Incentive Plan	Xcel Energy inc. Form 10-K for the year ended Dec. 31, 2015	001-03034	10.29
10.24*+	Fifth Amendment Exhibit 10.02 dated May 3, 2016	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2016	001-03034	10.01
10.25*	Second Amendment and Restated Credit Agreement, dated as of June 20, 2016 among Xcel Energy Inc., as borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association and the Bank of Tokyo-Mitsubishi UFJ, Ltd. , as Document Agents	Xcel Energy Inc. Form 8-K dated June 20, 2016	001-03034	99.01
10.26*+	Third Amendment to Exhibit 10.11 dated Sept. 30, 2016	Xcel Energy inc. Form 10-Q for the quarter ended Sept. 30, 2016	001-03034	10.01
10.27*+	Form of Xcel Energy, Inc. 2015 Omnibus Incentive Plan Award Agreement and Award Terms and Conditions under the Xcel Energy Inc. 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2016	001-03034	10.27
10.28*+	Fourth Amendment to Exhibit 10.11 dated Oct. 23, 2017	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2017	001-03034	10.1
10.29*	364-Day Term Loan Agreement dated Dec. 5, 2017 among Xcel Energy Inc., as Borrower, the several lenders from time to time parties thereto, and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Administrative Agent	Xcel Energy Inc. Form 8-K dated Dec. 5, 2017	001-03034	99.01
10.30*+	Sixth Amendment to Exhibit 10.02 dated Feb. 22, 2018	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2017	001-03034	10.30
10.31*+	Seventh Amendment to Exhibit 10.02 dated May 7, 2018	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2018	001-03034	10.01
10.32*	Forward Sale Agreement, dated Nov. 7, 2018, between Xcel Energy Inc. and Morgan Stanley &Co., LLC	Xcel Energy Inc. Form 8-K dated Nov. 7, 2018	001-03034	10.01
10.33*	Amended and Restated 364-Day Term Loan Agreement dated as of Dec. 4, 2018 among Xcel Energy Inc., as Borrower, the several lenders from time to time parties thereto, and MUFG Bank, Ltd. as Administrative Agent.	Xcel Energy Inc. Form 8-K dated Dec. 4, 2018	001-03034	99.01
10.34+	Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan			
10.35+	Form of Xcel Energy Inc. 2015 Omnibus Incentive Plan Award Agreement Terms and Conditions under the Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan			
10.36+	Stock Program for Non-Employee Directors of Xcel Energy Inc. as Amended and Restated on Dec. 12, 2017 under the 2015 Omnibus Incentive Plan			
NSP-Minnesota				
4.11*	Supplemental and Restated Trust Indenture, dated May 1, 1988, from NSP-Minnesota to Harris Trust and Savings Bank, as Trustee, providing for the issuance of First Mortgage Bonds, Supplemental Indentures between NSP-Minnesota and said Trustee	Xcel Energy Inc. Form S-3 dated April 18, 2018	001-03034	4(b)(3)
4.12*	Supplemental Trust Indenture dated June 1, 1995, creating $250 million principal amount of 7.125% First Mortgage Bonds, Series due July 1, 2025	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2017	001-03034	4.11
4.13*	Supplemental Trust (Indenture dated March 1, 1998, creating $150 million principal amount of 6.5% First Mortgage Bonds, Series due March 1, 2028	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2017	001-03034	4.12

4.14*	Supplemental Trust Indenture dated Aug. 1, 2000 (Assignment and Assumption of Trust Indenture)	NSP-Minnesota Form 10-12G dated Oct. 5, 2000	000-31709	4.51
4.15*	Indenture, dated July 1, 1999, between NSP-Minnesota and Norwest Bank Minnesota, NA, as Trustee, providing for the issuance of Sr. Debt Securities	Xcel Energy Inc. Form S-3 dated April 18, 2018	001-03034	4(b)(7)
4.16*	Supplemental Indenture, dated Aug. 18, 2000, supplemental to the Indenture dated July 1, 1999, among Xcel Energy, NSP-Minnesota and Wells Fargo Bank Minnesota, NA, as Trustee	NSP-Minnesota Form 10-12G dated Oct. 5, 2000	000-31709	4.63
4.17*	Supplemental Trust Indenture dated July 1, 2005 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $250 million principal amount of 5.25% First Mortgage Bonds, Series due July 15, 2035	NSP-Minnesota Form 8-K dated July 14, 2005	001-31387	4.01
4.18*	Supplemental Trust Indenture dated May 1, 2006 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $400 million principal amount of 6.25% First Mortgage Bonds, Series due June 1, 2036	NSP-Minnesota Form 8-K dated May 18, 2006	001-31387	4.01
4.19*	Supplemental Trust Indenture, dated June 1, 2007, between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee	NSP-Minnesota Form 8-K dated June 19, 2007	001-31387	4.01
4.20*	Supplemental Trust Indenture dated as of Nov. 1, 2009 between NSP-Minnesota and the Bank of New York Mellon Trust Co., NA, as successor Trustee, creating $300 million principal amount of 5.35% First Mortgage Bonds, Series due Nov. 1, 2039	NSP-Minnesota Form 8-K dated Nov. 16, 2009	001-31387	4.01
4.21*	Supplemental Trust Indenture dated as of Aug. 1, 2010 between NSP-Minnesota and the Bank of New York Mellon Trust Company, NA, as successor Trustee, creating $250 million principal amount of 1.95% First Mortgage Bonds, Series due Aug. 15, 2015 and $250 principal amount of 4.85% First Mortgage Bonds, Series due Aug. 15, 2040	NSP-Minnesota Form 8-K dated Aug. 4, 2010	001-31387	4.01
4.22*	Supplemental Trust Indenture dated as of Aug. 1, 2012 between NSP-Minnesota and the Bank of New York Mellon Trust Company, NA, as successor Trustee, creating $300 million principal amount of 2.15% First Mortgage Bonds, Series due Aug. 15, 2022 and $500 million principal amount of 3.40% First Mortgage Bonds, Series due Aug. 15, 2042	NSP-Minnesota Form 8-K dated Aug. 13, 2012	001-31387	4.01
4.23*	Supplemental Trust Indenture dated as of May 1, 2013 between NSP-Minnesota and the Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $400 million principal amount of 2.60% First Mortgage Bonds, Series due May 15, 2023	NSP-Minnesota Form 8-K dated May 20, 2013	001-31387	4.01
4.24*	Supplemental Trust Indenture dated as of May 1, 2014 between NSP-Minnesota and the Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $300 million principal amount of 4.125% First Mortgage Bonds, Series due May 15, 2044	NSP-Minnesota Form 8-K dated May 13, 2014	001-31387	4.01
4.25*	Supplemental Trust Indenture dated as of Aug. 1, 2015 between NSP-Minnesota and the Bank of New York Mellon Company, N.A., as successor Trustee, creating $300 million principal amount of 2.20% First Mortgage Bonds, Series due Aug. 15, 2020 and $300 million principal amount of 4.00% First Mortgage Bonds, Series due Aug. 15, 2045	NSP-Minnesota Form 8-K dated Aug. 11, 2015	001-31387	4.01
4.26*	Supplemental Trust Indenture dated as of May 1, 2016 between NSP-Minnesota and the Bank of NY Mellon Trust Company, N.A., as successor Trustee, creating $350 million principal amount of 3.60% First Mortgage Bonds, Series due May 31, 2046	NSP-Minnesota Form 8-K dated May 31, 2016	001-31387	4.01
4.27*	Supplemental Trust Indenture dated as of Sept. 1, 2017 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $600 million principal amount of 3.60% First Mortgage Bonds, Series due Sept. 15, 2047	NSP-Minnesota Form 8-K dated Sept. 13, 2017	001-31387	4.01
10.37*	Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota	NSP-Wisconsin Form S-4 dated Jan. 21, 2004	333-112033	10.01
10.38*	Second Amendment and Restated Credit Agreement, dated as of June 20, 2016 among NSP-Minnesota, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association and the Bank of Tokyo-Mitsubishi UFJ, Ltd., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 20, 2016	001-03034	99.02

NSP-Wisconsin

4.28*	Supplemental and Restated Trust Indenture, dated March 1, 1991, between NSP-Wisconsin and First Wisconsin Trust Company, providing for the issuance of First Mortgage Bonds	Xcel Energy Inc. Form S-3 dated April 18, 2018	001-03034	4(c)(3)
4.29*	Trust Indenture dated Sept. 1, 2000 between NSP-Wisconsin and Firstar Bank, NA as Trustee	NSP-Wisconsin Form 8-K dated Sept. 25, 2000	001-03140	4.01
4.30*	Supplemental Trust Indenture dated as of Sept. 1, 2003 between NSP-Wisconsin and U.S. Bank National Association, supplementing indentures dated April 1, 1947 and March 1, 1991	Xcel Energy Inc Form 10-Q for the quarter ended Sept. 30, 2003	001-03034	4.05
4.31*	Supplemental Trust Indenture dated as of Sept. 1, 2008 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $200 million principal amount of 6.375% First Mortgage Bonds, Series due Sept. 1, 2038	NSP-Wisconsin Form 8-K dated Sept. 3, 2008	001-03140	4.01
4.32*	Supplemental Trust Indenture dated as of Oct. 1, 2012 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $100 million principal amount of 3.70% First Mortgage Bonds, Series due Oct. 1, 2042	NSP-Wisconsin Form 8-K dated Oct. 10, 2012	001-03140	4.01
4.33*	Supplemental Trust Indenture dated as of June 1, 2014 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $100 million principal amount of 3.30% First Mortgage Bonds, Series due June 1, 2024	NSP-Wisconsin Form 8-K dated June 23, 2014	001-03140	4.01
4.34*	Supplemental Trust Indenture dated as of Nov 1, 2017 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $100 million in aggregate principal amount of 3.75% First Mortgage Bonds, Series due Dec. 1, 2047	NSP-Wisconsin Form 8-K dated Dec. 4, 2017	001-03140	4.01
4.35*	Supplemental Indenture dated as of Sept. 1, 2018 between Northern States Power Company and U.S. Bank National Association, as successor Trustee, creating 4.20% First Mortgage Bonds, Series due Sept. 1, 2048	NSP-Wisconsin to Form 8-K dated Sept. 12, 2018	001-03034	4.01
10.39*	Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota	NSP-Wisconsin Form S-4 dated Jan. 21, 2004	333-112033	10.01

10.40*	Second Amended and Restated Credit Agreement, dated as of June 20, 2016 among NSP-Wisconsin, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association and the Bank of Tokyo-Mitsubishi UFJ, Ltd., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 20, 2016		99.05
PSCo				
4.36*	Indenture, dated as of Oct. 1, 1993 between PSCo and Morgan Guaranty Trust Company of New York, as Trustee, providing for the issuance of First Collateral Trust Bonds	Xcel Energy Inc. Form S-3 dated April 18, 2018	001-03034	4(d)(3)
4.37*	Indenture dated July 1, 1999, between PSCo and The Bank of New York, providing for the issuance of Senior Debt Securities and First Supplemental Indenture dated July 14, 1999 between PSCo and the Bank of New York	PSCo Form 8-K dated July 13, 1999	001-03280	4.1 4.2
4.38*	Supplemental Indenture, dated Aug. 1, 2007 between PSCo and U.S. Bank Trust National Association, as successor Trustee	PSCo Form 8-K dated Aug. 8, 2007	001-03280	4.01
4.39*	Supplemental Indenture dated as of Aug. 1, 2008 between PSCo and U.S. Bank Trust National Association, as successor Trustee, creating $300 million principal amount of 5.80% First Mortgage Bonds, Series No. 18 due 2018 and $300 million principal amount of 6.50% First Mortgage Bonds, Series No. 19 due 2038	PSCo Form 8-K dated Aug. 6, 2008	001-03280	4.01
4.40*	Supplemental Indenture dated as of May 1, 2009 between PSCo and U.S. Bank Trust National Association, as successor Trustee, creating $400 million principal amount of 5.125% First Mortgage Bonds, Series No. 20 due 2019	PSCo Form 8-K dated May 28, 2009	001-03280	4.01
4.41*	Supplemental Indenture dated as of Nov. 1, 2010 between PSCo and U.S. Bank National Association, as successor Trustee, creating $400 million principal amount of 3.20% First Mortgage Bonds, Series No. 21 due 2020	PSCo Form 8-K dated Nov. 8, 2010	001-03280	4.01
4.42*	Supplemental Indenture dated as of Aug. 1, 2011 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 4.75% First Mortgage Bonds, Series No. 22 due 2041	PSCo Form 8-K dated Aug. 9, 2011	001-03280	4.01
4.43*	Supplemental Indenture dated as of Sept. 1, 2012 between PSCo and U.S. Bank National Association, as successor Trustee, creating $300 million principal amount of 2.25% First Mortgage Bonds, Series No. 23 due 2022 and $500 million principal amount of 3.60% First Mortgage Bonds, Series No. 24 due 2042	PSCo Form 8-K dated Sept. 11, 2012	001-03280	4.01
4.44*	Supplemental Indenture dated as of March 1, 2013 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 2.50% First Mortgage Bonds, Series No. 25 due 2023 and $250 million principal amount of 3.95% First Mortgage Bonds, Series No. 26 due 2043	PSCo Form 8-K dated March 26, 2013	001-03280	4.01
4.45*	Supplemental Indenture dated as of March 1, 2014 between PSCo and U.S. Bank National Association, as successor Trustee, creating $300 million principal amount of 4.30% First Mortgage Bonds, Series No. 27 due 2044	PSCo Form 8-K dated March 10, 2014	001-03280	4.01
4.46*	Supplemental Indenture dated as of May 1, 2015 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 2.90% First Mortgage Bonds, Series No. 28 due 2025	PSCo Form 8-K dated May 12, 2015	001-03280	4.01
4.47*	Supplemental Indenture dated as of June 1, 2016 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 3.55% First Mortgage Bonds, Series No. 29 due 2046	PSCo Form 8-K dated June 13, 2016	001-03280	4.01
4.48*	Supplemental Indenture No. 27 dated as of June 1, 2017 between PSCo and U.S. Bank National Association, as successor Trustee, creating $400 million principal amount of 3.80% First Mortgage Bonds, Series No. 30 due 2047	PSCo Form 8-K dated June 19, 2017	001-03280	4.01
4.49*	Supplemental Indenture dated as of June 1, 2018 between PSCo and U.S. Bank National Association, as successor Trustee, creating $350 million principal amount of 3.70% First Mortgage Bonds, Series No. 31 due 2028, and $350 million principal amount of 4.10% First Mortgage Bonds, Series No. 32 due 2048	PSCo Form 8-K dated June 21, 2018	001-03280	4.01
10.41*	Proposed Settlement Agreement, excerpts, as filed with the CPUC	Xcel Energy Inc. Form 8-K dated Dec. 3, 2004	001-03034	99.02
10.42*	Second Amended and Restated Credit Agreement, dated as of June 20, 2016 among PSCo, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association and the Bank of Tokyo-Mitsubishi UFJ, Ltd., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 20, 2016	001-03034	99.03
SPS				
4.50*	Indenture dated Feb. 1, 1999 between SPS and the Chase Manhattan Bank	SPS Form 8-K dated Feb. 25, 1999	001-03789	99.2
4.51*	Third Supplemental Indenture dated Oct. 1, 2003 to the indenture dated Feb. 1, 1999 between SPS and JPMorgan Chase Bank, as successor Trustee, creating $100 million principal amount of Series C and Series D Notes, 6% due 2033	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2003	001-03034	4.04
4.52*	Fourth Supplemental Indenture dated Oct. 1, 2006 between SPS and the Bank of New York, as successor Trustee	SPS Form 8-K dated Oct. 3, 2006	001-03789	4.01
4.53*	Indenture dated as of Aug. 1, 2011 between SPS and U.S. Bank National Association, as Trustee	SPS Form 8-K dated Aug. 10, 2011	001-03789	4.01
4.54*	Supplemental Indenture dated as of Aug. 3, 2011 between SPS and U.S. Bank National Association, as Trustee, creating $200 million principal amount of 4.50% First Mortgage Bonds, Series No. 1 due 2041	SPS Form 8-K dated Aug. 10, 2011	001-03789	4.02
4.55*	Sixth Supplemental Indenture dated as of June 1, 2014 between SPS and the Bank of New York Mellon Trust Company, N.A., as successor Trustee	SPS Form 8-K dated June 2, 2014	001-03789	4.03
4.56*	Supplemental Indenture No. 3 dated as of June 1, 2014 between SPS and U.S. Bank National Association, as Trustee, creating $150 million principal amount of 3.30% First Mortgage Bonds, Series No. 3 due 2024	SPS Form 8-K dated June 9, 2014	001-03789	4.02
4.57*	Supplemental Indenture dated as of Aug. 1, 2016 between SPS and U.S. Bank National Association, as Trustee, creating $300 million principal amount of 3.40% First Mortgage Bonds, Series No. 4 due 2046	SPS Form 8-K dated Aug. 12, 2016	001-03789	4.02

4.58*	Supplemental Indenture dated as of Aug. 1, 2017 between SPS and U.S. Bank National Association, as Trustee, creating $450 million principal amount of 3.70% First Mortgage Bonds, Series No. 5 due 2047	SPS Form 8-K dated Aug 9. 2017	001-03789	4.02
4.59*	Supplemental Indenture No. 6 dated as of Oct. 1, 2018 between SPS and U.S. Bank National Association, as Trustee, creating 4.40% First Mortgage Bonds, Series No. 6 due 2048	SPS Form 8-K dated Nov. 5, 2018	001-03789	4.02
10.43*	Second Amended and Restated Credit Agreement, dated as of June 20, 2016 among SPS, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 20, 2016	001-03034	99.04

Xcel Energy Inc.

21.01	Subsidiaries of Xcel Energy Inc.
23.01	Consent of Independent Registered Public Accounting Firm
24.01	Powers of Attorney
31.01	Principal Executive Officer’s certification pursuant to 18 U.S. C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.02	Principal Financial Officer’s certification pursuant to 18 U.S. C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101	The following materials from Xcel Energy Inc.’s Annual Report on Form 10-K for the year ended Dec. 31, 2018 are formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income, (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Balance Sheets, (v) the Consolidated Statements of Common Stockholders’ Equity, (vi) Notes to Consolidated Financial Statements, (vii) document and entity information, (viii) Schedule I, and (ix) Schedule II.

XCEL ENERGY INC.
CONDENSED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(amounts in millions, except per share data)

	Year Ended Dec. 31		
	2018	2017	2016
Income			
Equity earnings of subsidiaries	$ 1,393	$ 1,263	$ 1,199
Total income	1,393	1,263	1,199
Expenses and other deductions			
Operating expenses	24	30	22
Other income	(1)	(6)	(3)
Interest charges and financing costs	149	128	116
Total expenses and other deductions	172	152	135
Income before income taxes	1,221	1,111	1,064
Income tax benefit	(40)	(37)	(59)
Net income	$ 1,261	$ 1,148	$ 1,123
Other Comprehensive Income			
Pension and retiree medical benefits, net of tax of $1, $3 and $(3) respectively	$ 3	$ 4	$ (4)
Derivative instruments, net of tax of $(1), $2 and $2, respectively	(2)	3	4
Other comprehensive income (loss)	1	7	—
Comprehensive income	$ 1,262	$ 1,155	$ 1,123
Weighted average common shares outstanding:			
Basic	511	509	509
Diluted	511	509	509
Earnings per average common share:			
Basic	$ 2.47	$ 2.26	$ 2.21
Diluted	2.47	2.25	2.21

See Notes to Condensed Financial Statements

XCEL ENERGY INC.
CONDENSED STATEMENTS OF CASH FLOWS
(amounts in millions)

	Year Ended Dec. 31		
	2018	2017	2016
Operating activities			
Net cash provided by operating activities	$ 1,210	$ 1,208	$ 817
Investing activities			
Capital contributions to subsidiaries	(809)	(849)	(414)
Investments in the utility money pool	(2,578)	(1,258)	(1,880)
Return of investments in the utility money pool	2,493	1,173	1,880
Net cash used in investing activities	(894)	(934)	(414)
Financing activities			
Proceeds from (repayment of) short-term borrowings, net	(295)	715	(516)
Proceeds from issuance of long-term debt	492	—	1,539
Repayment of long-term debt	—	(250)	(704)
Proceeds from issuance of common stock	230	—	—
Repurchase of common stock	(1)	(3)	(32)
Dividends paid	(730)	(721)	(681)
Other	(12)	(14)	(9)
Net cash (used in) provided by financing activities	(316)	(273)	(403)
Net change in cash and cash equivalents	—	1	—
Cash and cash equivalents at beginning of period	1	—	—
Cash and cash equivalents at end of period	$ 1	$ 1	$ —

See Notes to Condensed Financial Statements

XCEL ENERGY INC.
CONDENSED BALANCE SHEETS
(amounts in millions)

	Dec. 31	
	2018	2017
Assets		
Cash and cash equivalents	$ 1	$ 1
Accounts receivable from subsidiaries	309	302
Other current assets	1	1
Total current assets	311	304
Investment in subsidiaries	15,965	14,932
Other assets	44	103
Total other assets	16,009	15,035
Total assets	$ 16,320	$ 15,339
Liabilities and Equity		
Current portion of long-term debt	$ —	$ —
Dividends payable	195	183
Short-term debt	488	783
Other current liabilities	10	11
Total current liabilities	693	977
Other liabilities	32	29
Total other liabilities	32	29
Commitments and contingencies		
Capitalization		
Long-term debt	3,373	2,878
Common stockholders' equity	12,222	11,455
Total capitalization	15,595	14,333
Total liabilities and equity	$ 16,320	$ 15,339

See Notes to Condensed Financial Statements

NOTES TO CONDENSED FINANCIAL STATEMENTS

Incorporated by reference are Xcel Energy's consolidated statements of common stockholders' equity and other comprehensive income in Part II, Item 8.

Basis of Presentation — The condensed financial information of Xcel Energy Inc. is presented to comply with Rule 12-04 of Regulation S-X. Xcel Energy Inc.'s investments in subsidiaries are presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in net assets of the subsidiaries are recorded in the balance sheets. The income from operations of the subsidiaries is reported on a net basis as equity in income of subsidiaries.

As a holding company with no business operations, Xcel Energy Inc.'s assets consist primarily of investments in its utility subsidiaries. Xcel Energy Inc.'s material cash inflows are only from dividends and other payments received from its utility subsidiaries and the proceeds raised from the sale of debt and equity securities. The ability of its utility subsidiaries to make dividend and other payments is subject to the availability of funds after taking into account their respective funding requirements, the terms of their respective indebtedness, the regulations of the FERC under the Federal Power Act, and applicable state laws. Management does not expect maintaining these requirements to have an impact on Xcel Energy Inc.'s ability to pay dividends at the current level in the foreseeable future. Each of its utility subsidiaries, however, is legally distinct and has no obligation, contingent or otherwise, to make funds available to Xcel Energy Inc.

Guarantees and Indemnifications

Xcel Energy Inc. provides guarantees and bond indemnities under specified agreements or transactions, which guarantee payment or performance. Xcel Energy Inc.'s exposure is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees and bond indemnities issued by Xcel Energy Inc. limit the exposure to a maximum stated amount. As of Dec. 31, 2018 and 2017, Xcel Energy Inc. had no assets held as collateral related to guarantees, bond indemnities and indemnification agreements.

Guarantees and bond indemnities issued and outstanding as of Dec. 31, 2018:

(Millions of Dollars)	Guarantor	Guarantee Amount	Current Exposure	Triggering Event
Guarantee of the indemnification obligations of Xcel Energy Services Inc. under the aircraft leases [(a)]	Xcel Energy Inc.	$ 11.0	$ —	[(d)]
Guarantee of loan for Hiawatha Collegiate High School [(b)]	Xcel Energy Inc.	1.0	—	[(d)]
Total guarantees issued		12.0	$ —	
Guarantee performance and payment of surety bonds for Xcel Energy Inc.'s utility subsidiaries [(c)]	Xcel Energy Inc.	$ 51.1	[(f)]	[(e)]

(a) The terms of this guarantee expires in 2021 and 2023 when the associated leases expire.

(b) The term of this guarantee expires the earlier of 2024 or full repayment of the loan.

(c) The surety bonds primarily relate to workers compensation benefits and utility projects. The workers compensation bonds are renewed annually and the project based bonds expire in conjunction with the completion of the related projects.

(d) Nonperformance and/or nonpayment.

(e) Per the indemnity agreement between Xcel Energy Inc. and the various surety companies, surety companies have the discretion to demand that collateral be posted.

(f) Due to the magnitude of projects associated with the surety bonds, the total current exposure of this indemnification cannot be determined. Xcel Energy Inc. believes the exposure to be significantly less than the total amount of the outstanding bonds.

Indemnification Agreements

Xcel Energy Inc. provides indemnifications through contracts entered into in the normal course of business. Indemnifications are primarily against adverse litigation outcomes in connection with underwriting agreements, breaches of representations and warranties, including corporate existence, transaction authorization and certain income tax matters. Obligations under these agreements may be limited in terms of duration or amount. Maximum future payments under these indemnifications cannot be reasonably estimated as the dollar amounts are often not explicitly stated.

Related Party Transactions — Xcel Energy Inc. presents related party receivables net of payables. Accounts receivable and payable with affiliates at Dec. 31:

	2018		2017	
(Millions of Dollars)	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Minnesota	$ 117	$ —	$ 68	$ —
NSP-Wisconsin	3	—	13	—
PSCo	29	—	69	—
SPS	39	—	26	—
Xcel Energy Services Inc.	96	—	95	—
Xcel Energy Ventures Inc.	13	—	14	—
Other subsidiaries of Xcel Energy Inc.	12	—	17	—
	$ 309	$ —	$ 302	$ —

Dividends — Cash dividends paid to Xcel Energy Inc. by its subsidiaries were $1,097 million, $1,063 million and $923 million for the years ended Dec. 31, 2018, 2017 and 2016, respectively. These cash receipts are included in operating cash flows of the condensed statements of cash flows.

Money Pool — FERC approval was received to establish a utility money pool arrangement with the utility subsidiaries, subject to receipt of required state regulatory approvals. The utility money pool allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc.

Money pool lending for Xcel Energy Inc.:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2018
Loan outstanding at period end	$ —
Average loan outstanding	59
Maximum loan outstanding	172
Weighted average interest rate, computed on a daily basis	2.22%
Weighted average interest rate at end of period	N/A
Money pool interest income	$ 0.3

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31, 2018	Year Ended Dec. 31, 2017	Year Ended Dec. 31, 2016
Loan outstanding at period end	$ —	$ 85	$ —
Average loan outstanding	71	38	66
Maximum loan outstanding	243	226	211
Weighted average interest rate, computed on a daily basis	1.95%	1.13%	0.69%
Weighted average interest rate at end of period	N/A	1.18	N/A
Money pool interest income	$ 1.4	$ 0.4	$ 0.5

See notes to the consolidated financial statements in Part II, Item 8.

SCHEDULE II

XCEL ENERGY INC. AND SUBSIDIARIES VALUATION AND QUALIFYING ACCOUNTS YEARS ENDED DEC. 31

	Allowance for bad debts			NOL and tax credit valuation allowances		
(Millions of Dollars)	2018	2017	2016	2018	2017	2016
Balance at Jan. 1	$ 52	$ 51	$ 52	$ 77	$ 58	$ 28
Additions Charged to Costs and Expenses	42	39	39	7	9	3
Additions Charged to Other Accounts	11	10	11	— (a)	22 (a)	35 (a)
Deductions from Reserves	(50)	(48)	(51)	(5) (b)	(12) (b)	(8) (b)
Balance at Dec. 31	$ 55	$ 52	$ 51	$ 79	$ 77	$ 58

(a) The 2016 - 2017 changes are the accrual of valuation allowances for North Dakota ITC, net of federal income tax benefit, that is offset to a regulatory liability; the 2017 change includes $14 million expense related to the revaluation of federal benefit as a result of the TCJA.

(b) Primarily the reductions to valuation allowances for North Dakota ITC carryforwards, net of federal benefit, primarily due to a consolidated adjustment to the regulatory liability accrual referenced above; the 2017 change includes $4 million of reduced expense related to the revaluation of federal benefit as a result of TCJA.

Item 16 — Form 10-K Summary

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this annual report to be signed on its behalf by the undersigned thereunto duly authorized.

XCEL ENERGY INC.

Feb. 22, 2019	By:	/s/ ROBERT C. FRENZEL
		Robert C. Frenzel
		Executive Vice President, Chief Financial Officer
		(Principal Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities on the date indicated above.

	/s/ BEN FOWKE Ben Fowke	Chairman, President, Chief Executive Officer and Director (Principal Executive Officer)
	/s/ ROBERT C. FRENZEL Robert C. Frenzel	Executive Vice President, Chief Financial Officer (Principal Financial Officer)
	/s/ JEFFREY S. SAVAGE Jeffrey S. Savage	Senior Vice President, Controller (Principal Accounting Officer)
*	Lynn Casey	Director
*	Richard K. Davis	Director
*	Richard T. O'Brien	Director
*	David K. Owens	Director
*	Christopher J. Policinski	Director
*	James Prokopanko	Director
*	A. Patricia Sampson	Director
*	James J. Sheppard	Director
*	David A. Westerlund	Director
*	Kim Williams	Director
*	Timothy V. Wolf	Director
*	Daniel Yohannes	Director
*By:	/s/ ROBERT C. FRENZEL Robert C. Frenzel	Attorney-in-Fact

Shareholder Information

Headquarters
414 Nicollet Mall, Minneapolis, MN 55401

Website
xcelenergy.com

Stock Transfer Agent
EQ Shareowner Services
1110 Centre Pointe Curve, Suite 101
Mendota Heights, MN 55120
Telephone: 877.778.6786, toll free

Reports Available Online
Financial reports, including filings with the Securities and Exchange Commission and Xcel Energy's Report to Shareholders, are available online at xcelenergy.com; click on Investor Relations. Other information about Xcel Energy, including our Code of Conduct, Guidelines on Corporate Governance, Corporate Responsibility Report and Committee Charters, is also available at xcelenergy.com.

Stock Exchange Listings and Ticker Symbol
Common stock is listed on the Nasdaq Global Select Market (Nasdaq) under the ticker symbol XEL. In newspaper listings, it appears as XcelEngy.

Investor Relations
Website: xcelenergy.com or contact Paul Johnson, Vice President, Investor Relations, at 612.215.4535.

Shareholder Services
Website: xcelenergy.com or contact Darin Norman, Senior Analyst, Investor Relations, at 612.337.2310 or email darin.norman@xcelenergy.com.

Corporate Governance
Xcel Energy has filed with the Securities and Exchange Commission certifications of its Chief Executive Officer and Chief Financial Officer pursuant to section 302 of the Sarbanes-Oxley Act of 2002 as exhibits to its Annual Report on Form 10-K for 2018. It has also filed with the New York Stock Exchange the CEO certification for 2018 required by section 303A.12(a) of the New York Stock Exchange's rules relating to compliance with the New York Stock Exchange's corporate governance listing standards.

To contact the Board of Directors, send an email to boardofdirectors@xcelenergy.com.

You also may direct questions to the Corporate Secretary's Department at corporatesecretary@xcelenergy.com.

The Xcel Energy Board of Directors (from left to right): Tim Wolf, Richard Davis, David Westerlund, Lynn Casey, Chris Policinski, David Owens, Ben Fowke, Kim Williams, Richard O'Brien, Daniel Yohannes, Jim Prokopanko, James Sheppard and Pat Sampson.

Xcel Energy Board of Directors

Lynn Casey [3,4]
Chair, Padilla

Richard K. Davis [2,3]
President and CEO,
Make-A-Wish Foundation

Ben Fowke
Chairman, President and CEO
Xcel Energy Inc.

Richard T. O'Brien [1, 4]
Independent Consultant

David K. Owens [3, 4]
Retired Executive
Edison Electric Institute

Christopher J. Policinski [2]
Lead Independent Director
Retired President and CEO
Land O' Lakes, Inc.

James Prokopanko [2, 4]
Retired President and CEO
The Mosaic Company

A. Patricia Sampson [1, 3]
CEO, President and Owner
The Sampson Group, Inc.

James J. Sheppard [2, 4]
Independent Consultant

David A. Westerlund [1, 2]
Retired Executive Vice President,
Administration and Corporate Secretary
Ball Corporation

Kim Williams [1, 3]
Retired Partner
Wellington Management Company LLP

Timothy V. Wolf [3, 4]
President
Wolf Interests, Inc.

Daniel Yohannes [1, 3]
Former United States Ambassador
to the Organization for Economic
Cooperation and Development

Board Committees:
1. Audit
2. Governance, Compensation and Nominating
3. Finance
4. Operations, Nuclear, Environmental and Safety

Fiscal Agents

XCEL ENERGY INC.

Transfer Agent, Registrar, Dividend Distribution, Common Stock
EQ Shareowner Services,
1110 Centre Pointe Curve, Suite 101
Mendota Heights, MN 55120

Trustee–Bonds
Wells Fargo Bank, N.A., Corporate Trust Services
150 East 42nd Street, 40th Floor,
New York, NY 10017

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